PUBLIC SERVICE COMPANY OF OKLAHOMA

PUBLIC SERVICE COMPANY OF OKLAHOMA
SELECTED FINANCIAL DATA

	2003	2002	2001	2000	1999
			(in thousands)		
INCOME STATEMENTS DATA					
Operating Revenues	$1,102,822	$793,647	$957,000	$956,398	$749,390
Operating Expenses	1,009,959	708,926	860,012	859,729	650,677
Operating Income	92,863	84,721	96,988	96,669	98,713
Nonoperating Items, Net	5,812	(3,239)	20	8,974	946
Interest Charges	44,784	40,422	39,249	38,980	38,151
Net Income	53,891	41,060	57,759	66,663	61,508
Preferred Stock Dividend Requirements	213	213	213	212	212
Gain on Reacquired Preferred Stock	-	1	-	-	-
Earnings Applicable to Common Stock	$53,678	$40,848	$57,546	$66,451	$61,296
BALANCE SHEETS DATA					
Electric Utility Plant	$2,806,396	$2,759,504	$2,695,099	$2,604,670	$2,459,705
Accumulated Depreciation and Amortization	1,069,216	1,037,222	989,426	963,176	935,946
Net Electric Utility Plant	$1,737,180	$1,722,282	$1,705,673	$1,641,494	$1,523,759
TOTAL ASSETS	$1,970,032	$1,979,323	$1,943,928	$2,325,500	$1,703,155
Common Stock and Paid-in Capital	$387,246	$337,246	$337,246	$337,246	$337,246
Retained Earnings	139,604	116,474	142,994	137,688	139,237
Accumulated Other Comprehensive Income (Loss)	(43,842)	(54,473)	-	-	-
Total Common Shareholder's Equity	$483,008	$399,247	$480,240	$474,934	$476,483
Cumulative Preferred Stock Not Subject to Mandatory Redemption	$5,267	$5,267	$5,267	$5,267	$5,270
Trust Preferred Securities (a)	$-	$75,000	$75,000	$75,000	$75,000
Long-term Debt (b)	$574,298	$545,437	$451,129	$470,822	$384,516
Obligations Under Capital Leases (b)	$1,010	$-	$-	$-	$-
TOTAL CAPITALIZATION AND LIABILITIES	$1,970,032	$1,979,323	$1,943,928	$2,325,500	$1,703,155

(a) See Note 16 of the Notes to Respective Financial Statements.
(b) Including portion due within one year.

PUBLIC SERVICE COMPANY OF OKLAHOMA
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

Public Service Company of Oklahoma (PSO) is a public utility engaged in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to approximately 505,000 retail customers in eastern and southwestern Oklahoma. As a power pool member with AEP West companies, we share in the revenues and expenses of the power pool's sales to neighboring utilities and power marketers. PSO also sells electric power at wholesale to other utilities, municipalities and rural electric cooperatives.

Power pool members are compensated for energy delivered to other members based upon the delivering members' incremental cost plus a portion of the savings realized by the purchasing member that avoids the use of more costly alternatives. The revenue and costs for sales to neighboring utilities and power marketers made by AEPSC on behalf of the AEP West companies are shared among the members based upon the relative magnitude of the energy each member provides to make such sales.

Power and gas risk management activities are conducted on our behalf by AEPSC. We share in the revenues and expenses associated with these risk management activities with other AEP registrant subsidiaries excluding AEGCo under existing power pool and system integration agreements. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas. The electricity and gas contracts include physical transactions, over-the-counter options and swaps and exchange traded futures and options. The majority of the physical forward contracts are typically settled by entering into offsetting contracts.

Under our system integration agreement, revenues and expenses from the sales to neighboring utilities, power marketers and other power and gas risk management entities are shared among AEP East and West companies. Sharing in a calendar year is based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger of AEP and CSW. This resulted in an AEP East and West companies' allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year may also be based upon the relative generating capacity of the AEP East and West companies in the event the pre-merger activity level is exceeded. The capacity based allocation mechanism was triggered in June 2003, resulting in an allocation factor of approximately 70% and 30% for the AEP East and West companies, respectively, for the remainder of 2003.

Results of Operations

2003 Compared to 2002

Net Income increased $13 million for the year. The increase for the year was due mainly to higher retail base revenue and wholesale margins. Significant fluctuations occurred in revenues, fuel and purchased power due to certain ICR adjustments in 2002 and changing natural gas prices; however, operating income was not significantly affected due to the functioning of the fuel adjustment clause in Oklahoma.

Operating Income

Operating Income increased $8 million primarily due to:

- Increased wholesale margins of $9 million due to an increase in our allocation percentage, in AEP's Power Pool, resulting from increased amounts of off-system sales.
- Increased retail base revenue of $6 million (2%), resulting mainly from a 6% increase in KWH sold. Cooling degree-days decreased 3% while heating degree-days increased 1%.
- Decreased Other Operation expense of $4 million which has several contributing factors including administrative and support expenses, outside services and related expenses.
- Decreased Taxes Other Than Income Taxes of $2 million due primarily to decreased franchise taxes.

The increase in Operating Income was partially offset by:

- Increased Maintenance expense of $5 million due mainly to increased plant maintenance and tree trimming.
- Increased Income Taxes of $13 million due to an increase in pre-tax operating income and increases in tax return and tax accrual adjustments.

Other Impacts on Earnings

Nonoperating Income increased $6 million primarily due to higher margins from risk management activities and gains on the disposition of excess land.

Nonoperating Expenses decreased $6 million due to the 2002 write-down of certain non-utility investments.

Interest Charges increased $4 million as a result of replacing floating rate short-term debt with long-term fixed rate unsecured debt.

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Current ratings are as follows:

	Moody's	S&P	Fitch
First Mortgage Bonds	A3	BBB	A
Senior Unsecured Debt	Baa1	BBB	A-

In February 2003, Moody's Investor Service (Moody's) completed their review of AEP and its rated subsidiaries. The results of that review included a downgrade of our rating for unsecured debt from A2 to Baa1 and secured debt from A1 to A3. The completion of this review was a culmination of ratings action started during 2002. In March 2003, S&P lowered AEP and our senior unsecured debt and first mortgage bonds ratings from BBB+ to BBB.

Summary Obligation Information

Our contractual obligations include amounts reported on the Consolidated Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes our contractual cash obligations at December 31, 2003:

	Payments Due by Period (in thousands)				
Contractual Cash Obligations	Less Than 1 year	2-3 years	4–5 years	After 5 years	Total
Long-term Debt	$83,700	$50,000	$1,000	$439,598	$574,298
Advances from Affiliates	32,864	-	-	-	32,864
Unconditional Purchase Obligation (a)	181,379	175,082	139,916	377,568	873,945
Capital Lease Obligations	492	562	50	-	1,104
Noncancellable Operating Leases	4,684	8,599	4,642	8,616	26,541
Total	$303,119	$234,243	$145,608	$825,782	$1,508,752

(a) Represents contractual obligations to purchase coal and natural gas as fuel for electric generation along with related transportation costs.

Significant Factors

See the "Registrants' Combined Management's Discussion and Analysis" section beginning on page M-1 for additional discussion of factors relevant to us.

Quantitative And Qualitative Disclosures About Risk Management Activities

Market Risks

Our risk management policies and procedures are instituted and administered at the AEP consolidated level. See complete discussion within AEP's "Qualitative And Quantitative Disclosures About Risk Management Activities" section. The following tables provide information about our risk management activities' effect on this specific registrant.

MTM Risk Management Contract Net Assets

This table provides detail on changes in our MTM net asset or liability balance sheet position from one period to the next.

MTM Risk Management Contract Net Assets
Year Ended December 31, 2003
(in thousands)

Domestic Power

Beginning Balance December 31, 2002	$3,545
(Gain) Loss from Contracts Realized/Settled During the Period (a)	1,308
Fair Value of New Contracts When Entered Into During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	(69)
Change in Fair Value Due to Valuation Methodology Changes	-
Effect of EITF 98-10 Rescission (d)	-
Changes in Fair Value of Risk Management Contracts (e)	-
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (f)	9,273
Total MTM Risk Management Contract Net Assets, Excluding Cash Flow Hedges	14,057
Net Cash Flow Hedge Contracts (g)	239
Ending Balance December 31, 2003	$14,296

(a)"(Gain) Loss from Contracts Realized/Settled During the Period" includes realized gains from risk management contracts and related derivatives that settled during 2003 that were entered into prior to 2003.

(b)The "Fair Value of New Contracts When Entered Into During the Period" represents the fair value of long-term contracts entered into with customers during 2003. The fair value is calculated as of the execution of the contract. Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. The contract prices are valued against market curves associated with the delivery location.

(c)"Net Option Premiums Paid/(Received)" reflects the net option premiums paid/(received) as they relate to unexercised and unexpired option contracts that were entered into in 2003.

(d)See Note 2 "New Accounting Pronouncements, Extraordinary Items and Cumulative Effect of Accounting Changes."

(e)"Changes in Fair Value of Risk Management Contracts" represents the fair value change in the risk management portfolio due to market fluctuations during the current period. Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.

(f)"Change in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.

(g) "Net Cash Flow Hedge Contracts (pre-tax)" are discussed below in Accumulated Other Comprehensive Income (Loss).

Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets

The table presenting maturity and source of fair value of MTM risk management contract net assets provides two fundamental pieces of information:

- The source of fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).
- The maturity, by year, of our net assets/liabilities, giving an indication of when these MTM amounts will settle and generate cash.

Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets Fair Value of Contracts as of December 31, 2003

	2004	2005	2006	2007	2008	After 2008	Total (c)
			(in thousands)				
Prices Actively Quoted – Exchange Exchange Traded Contracts	$326	$(136)	$13	$83	$-	$-	$286
Prices Provided by Other External Sources – OTC Broker Quotes (a)	6,962	2,151	788	497	285	-	10,683
Prices Based on Models and Other Valuation Methods (b)	(883)	676	155	325	680	2,135	3,088
Total	$6,405	$2,691	$956	$905	$965	$2,135	$14,057

(a) "Prices Provided by Other External Sources – OTC Broker Quotes reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.

(b)"Prices Based on Models and Other Valuation Methods" is in absence of pricing information from external sources, modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the Modeled category varies by market.

(c) Amounts exclude Cash Flow Hedges.

Cash Flow Hedges Included in Accumulated Other Comprehensive Income (Loss) (AOCI) on the Balance Sheet

The table provides detail on effective cash flow hedges under SFAS 133 included in the balance sheet. The data in the table will indicate the magnitude of SFAS 133 hedges we have in place. (However, given that under SFAS 133 only cash flow hedges are recorded in AOCI, the table does not provide an all-encompassing picture of our hedging activity). The table also includes a roll-forward of the AOCI balance sheet account, providing insight into the drivers of the changes (new hedges placed during the period, changes in value of existing hedges and roll off of hedges). In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Year Ended December 31, 2003

	Domestic Power (in thousands)
Beginning Balance December 31, 2002	$(42)
Changes in Fair Value (a)	18
Reclassifications from AOCI to Net Income (b)	180
Ending Balance December 31, 2003	$156

(a) "Changes in Fair Value" shows changes in the fair value of derivatives designated as hedging instruments in cash flow hedges during the reporting period not yet reclassified into net income, pending the hedged item's affecting net income. Amounts are reported net of related income taxes.

(b) "Reclassifications from AOCI to Net Income" represents gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into net income during the reporting period. Amounts are reported net of related income taxes above.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $724 thousand gain.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Risk Management Contracts

The following table shows the end, high, average, and low market risk as measured by VaR for year-to-date:

December 31, 2003 (in thousands)				December 31, 2002 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$258	$1,004	$420	$100	$136	$415	$148	$30

VaR Associated with Debt Outstanding

The risk of potential loss in fair value attributable to our exposure to interest rates, primarily related to long-term debt with fixed interest rates was $66 million and $70 million at December 31, 2003 and 2002, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period, therefore a near term change in interest rates should not negatively affect our results of operation or consolidated financial position.

PUBLIC SERVICE COMPANY OF OKLAHOMA
STATEMENTS OF INCOME
For the Years Ended December 31, 2003, 2002 and 2001

	2003	2002	2001
		(in thousands)	
OPERATING REVENUES			
Electric Generation, Transmission and Distribution	$1,079,692	$784,208	$920,229
Sales to AEP Affiliates	23,130	9,439	36,771
TOTAL	1,102,822	793,647	957,000
OPERATING EXPENSES			
Fuel for Electric Generation	526,563	246,199	461,470
Purchased Electricity for Resale	35,685	47,507	24,187
Purchased Electricity from AEP Affiliates	109,639	89,454	43,758
Other Operation	129,246	133,538	137,678
Maintenance	53,076	48,060	46,188
Depreciation and Amortization	86,455	85,896	80,245
Taxes Other Than Income Taxes	32,287	34,077	31,973
Income Taxes	37,008	24,195	34,513
TOTAL	1,009,959	708,926	860,012
OPERATING INCOME	92,863	84,721	96,988
Nonoperating Income	8,026	1,920	2,112
Nonoperating Expense	1,385	6,971	1,740
Nonoperating Income Tax Expense (Credit)	829	(1,812)	352
Interest Charges	44,784	40,422	39,249
NET INCOME	53,891	41,060	57,759
Gain on Reacquired Preferred Stock	-	1	-
Preferred Stock Dividend Requirements	213	213	213
EARNINGS APPLICABLE TO COMMON STOCK	$53,678	$40,848	$57,546

The common stock of PSO is owned by a wholly-owned subsidiary of AEP.

See Notes to Respective Financial Statements beginning on page L-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA
STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S
EQUITY AND COMPREHENSIVE INCOME
For the Years Ended December 31, 2003, 2002 and 2001
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2000	$157,230	$180,016	$137,688	$-	$474,934
Common Stock Dividends Declared			(52,240)		(52,240)
Preferred Stock Dividends Declared			(213)		(213)
TOTAL					422,481
COMPREHENSIVE INCOME					
NET INCOME			57,759		57,759
TOTAL COMPREHENSIVE INCOME					57,759
DECEMBER 31, 2001	$157,230	$180,016	$142,994	$-	$480,240
Gain on Reacquired Preferred Stock			1		1
Common Stock Dividends			(67,368)		(67,368)
Preferred Stock Dividends			(213)		(213)
TOTAL					412,660
COMPREHENSIVE INCOME					
Other Comprehensive Income, (Loss) Net of Taxes:					
Unrealized Loss on Cash Flow Hedges				(42)	(42)
Minimum Pension Liability				(54,431)	(54,431)
NET INCOME			41,060		41,060
TOTAL COMPREHENSIVE INCOME					(13,413)
DECEMBER 31, 2002	$157,230	$180,016	$116,474	$(54,473)	$399,247
Capital Contribution from Parent		50,000			50,000
Common Stock Dividends			(30,000)		(30,000)
Preferred Stock Dividends			(213)		(213)
Distribution of Investment in AEMT, Inc. Preferred Shares to Parent			(548)		(548)
TOTAL					418,486
COMPREHENSIVE INCOME					
Other Comprehensive Income Net of Taxes:					
Unrealized Gain on Cash Flow Hedges				198	198
Minimum Pension Liability				10,433	10,433
NET INCOME			53,891		53,891
TOTAL COMPREHENSIVE INCOME					64,522
DECEMBER 31, 2003	$157,230	$230,016	$139,604	$(43,842)	$483,008

See Notes to Respective Financial Statements beginning on page L-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA
BALANCE SHEETS
ASSETS
December 31, 2003 and 2002

	2003	2002
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	$1,065,408	$1,040,520
Transmission	451,292	432,846
Distribution	1,031,229	990,947
General	203,756	206,747
Construction Work in Progress	54,711	88,444
TOTAL	2,806,396	2,759,504
Accumulated Depreciation and Amortization	1,069,216	1,037,222
TOTAL - NET	1,737,180	1,722,282
OTHER PROPERTY AND INVESTMENTS		
Non-Utility Property, Net	4,631	4,833
Other Investments	2,320	550
TOTAL	6,951	5,383
CURRENT ASSETS		
Cash and Cash Equivalents	14,258	16,774
Accounts Receivable:		
Customers	28,515	30,130
Affiliated Companies	19,852	14,139
Miscellaneous	-	1,557
Allowance for Uncollectible Accounts	(37)	(84)
Fuel Inventory	18,331	19,973
Materials and Supplies	38,125	37,375
Regulatory Asset for Under-recovered Fuel Costs	24,170	76,470
Risk Management Assets	18,586	3,841
Margin Deposits	4,351	91
Prepayments and Other	2,655	2,644
TOTAL	168,806	202,910
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
Unamortized Loss on Required Debt	14,357	11,138
Other	14,342	15,012
Long-term Risk Management Assets	10,379	4,481
Deferred Charges	18,017	18,117
TOTAL	57,095	48,748
TOTAL ASSETS	$1,970,032	$1,979,323

See Notes to Respective Financial Statements beginning on page L-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA
BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
December 31, 2003 and 2002

	2003	2002
	(in thousands)	
CAPITALIZATION		
Common Shareholder's Equity:		
Common Stock – $15 Par Value:		
Authorized Shares: 11,000,000		
Issued Shares: 10,482,000		
Outstanding Shares: 9,013,000	$157,230	$157,230
Paid-in Capital	230,016	180,016
Retained Earnings	139,604	116,474
Accumulated Other Comprehensive Income (Loss)	(43,842)	(54,473)
Total Common Shareholder's Equity	483,008	399,247
Cumulative Preferred Stock Not Subject to Mandatory Redemption	5,267	5,267
Total Shareholder's Equity	488,275	404,514
PSO – Obligated, Mandatorily Redeemable Preferred Securities of Subsidiary Trust Holding Solely Junior Subordinated Debentures of PSO	-	75,000
Long-term Debt	490,598	445,437
TOTAL	978,873	924,951
CURRENT LIABILITIES		
Long-term Debt Due Within One Year	83,700	100,000
Advances from Affiliates	32,864	86,105
Accounts Payable:		
General	48,808	61,169
Affiliated Companies	57,206	78,076
Customer Deposits	26,547	21,789
Taxes Accrued	27,157	6,854
Interest Accrued	3,706	6,979
Risk Management Liabilities	11,067	3,260
Obligations Under Capital Leases	452	-
Other	35,234	24,957
TOTAL	326,741	389,189
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	335,434	341,396
Long-Term Risk Management Liabilities	3,602	1,581
Regulatory Liabilities:		
Asset Removal Costs	214,033	-
Deferred Investment Tax Credits	30,411	32,201
SFAS 109 Regulatory Liability, Net	24,937	27,893
Other	15,406	4,391
Obligations Under Capital Leases	558	-
Deferred Credits and Other	40,037	257,721
TOTAL	664,418	665,183
Commitments and Contingencies (Note 7)		
TOTAL CAPITALIZATION AND LIABILITIES	$1,970,032	$1,979,323

See Notes to Respective Financial Statements beginning on page L-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA
STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2003, 2002 and 2001

	2003	2002	2001
		(in thousands)	
OPERATING ACTIVITIES			
Net Income	$53,891	$41,060	$57,759
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:			
Depreciation and Amortization	86,455	85,896	80,245
Deferred Income Taxes	(14,641)	75,659	(17,751)
Deferred Investment Tax Credits	(1,790)	(1,791)	(1,791)
Changes in Certain Assets and Liabilities:			
Accounts Receivable, Net	(2,588)	(3,737)	21,405
Fuel, Materials and Supplies	892	996	(589)
Accounts Payable	(33,231)	25,629	(55,319)
Taxes Accrued	20,303	(11,296)	16,491
Fuel Recovery	52,300	(85,190)	51,987
Changes in Other Assets	(10,421)	1,796	(11,929)
Changes in Other Liabilities	14,987	(6,928)	9,351
Net Cash Flows From Operating Activities	166,157	122,094	149,859
INVESTING ACTIVITIES			
Construction Expenditures	(86,815)	(89,365)	(124,520)
Proceeds from Sale of Property and Other	2,862	963	(359)
Net Cash Flows Used For Investing Activities	(83,953)	(88,402)	(124,879)
FINANCING ACTIVITIES			
Capital Contributions from Parent	50,000	-	-
Issuance of Long-term Debt	148,734	187,850	-
Retirement of Long-term Debt	(200,000)	(106,000)	(20,000)
Change in Advances to/from Affiliates, Net	(53,241)	(36,982)	41,967
Dividends Paid on Common Stock	(30,000)	(67,368)	(52,240)
Dividends Paid on Cumulative Preferred Stock	(213)	(213)	(213)
Net Cash Flows Used For Financing Activities	(84,720)	(22,713)	(30,486)
Net Increase (Decrease) in Cash and Cash Equivalents	(2,516)	10,979	(5,506)
Cash and Cash Equivalents at Beginning of Period	16,774	5,795	11,301
Cash and Cash Equivalents at End of Period	$14,258	$16,774	$5,795

SUPPLEMENTAL DISCLOSURE:
Cash paid (received) for interest net of capitalized amounts was $44,703,000, $38,620,000 and $38,250,000 and for income taxes was $36,470,000, (38,943,000) and $38,653,000 in 2003, 2002 and 2001, respectively.

There was a non-cash distribution of $548,000 in preferred shares in AEMT, Inc. to PSO's Parent Company in 2003.

See Notes to Respective Financial Statements beginning on page L-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA
STATEMENTS OF CAPITALIZATION
December 31, 2003 and 2002

	2003	2002
	(in thousands)	
TOTAL COMMON SHAREHOLDER'S EQUITY	$483,008	$399,247

PREFERRED STOCK: Cumulative $100 par value – authorized shares 700,000, redeemable at the option of PSO upon 30 days notice.

Series	Call Price December 31, 2003	Number of Shares Redeemed Year Ended December 31, 2003	2002	2001	Shares Outstanding December 31, 2003		
Not Subject to Mandatory Redemption:							
4.00%	$105.75	2	6	-	44,598	4,460	4,460
4.24%	103.19	-	1	-	8,069	807	807
Total						5,267	5,267

TRUST PREFERRED SECURITIES:		
PSO-Obligated, Mandatorily Redeemable Preferred Securities of Subsidiary Trust Holding Solely Junior Subordinated Debentures of PSO, 8.00%, Due April 30, 2037 (a)	-	75,000
LONG-TERM DEBT (See Schedule of Long-term Debt):		
First Mortgage Bonds	99,864	298,079
Installment Purchase Contracts	47,358	47,358
Note Payable to Trust (a)	77,320	-
Senior Unsecured Notes	349,756	200,000
Less Portion Due Within One Year	(83,700)	(100,000)
Long-term Debt Excluding Portion Due Within One Year	490,598	445,437
TOTAL CAPITALIZATION	$978,873	$924,951

(a) See Note 16 for discussion of Notes Payable to Trust.

See Notes to Respective Financial Statements beginning on page L-1.

PUBLIC SERVICE COMPANY OF OKLAHOMA
SCHEDULE OF LONG-TERM DEBT
December 31, 2003 and 2002

First Mortgage Bonds outstanding were as follows:

% Rate	Due	2003	2002
		(in thousands)	
6.25	2003 – April 1	$-	$ 35,000
7.25	2003 – July 1	-	65,000
7.38	2004 – December 1	50,000	50,000
6.50	2005 – June 1	50,000	50,000
7.38	2023 – April 1	-	100,000
Unamortized Discount		(136)	(1,921)
Total		$99,864	$298,079

First Mortgage Bonds are secured by a first mortgage lien on electric utility plant. The indenture, as supplemented, relating to the first mortgage bonds contains maintenance and replacement provisions requiring the deposit of cash or bonds with the trustee, or in lieu thereof, certification of unfunded property additions. Interest payments are made semi-annually.

Installment Purchase Contracts have been entered into in connection with the issuance of pollution control revenue bonds by governmental authorities as follows:

	% Rate	Due	2003	2002
			(in thousands)	
Oklahoma Environmental Finance Authority (OEFA):				
	5.90	2007 - December 1	$1,000	$1,000
Oklahoma Development Finance Authority (ODFA):				
	4.875	2014 - June 1 (a)	33,700	33,700
Red River Authority of Texas:				
	6.00	2020 – June 1	12,660	12,660
	Unamortized Discount		(2)	(2)
	Total		$47,358	$47,358

(a) These bonds will be remarketed on June 1, 2004.

Under the terms of the installment purchase contracts, PSO is required to pay amounts sufficient to enable the payment of interest on and the principal of (at stated maturities and upon mandatory redemptions) related pollution control revenue bonds issued to finance the construction of pollution control facilities at certain plants. Interest payments are made semi-annually.

Senior Unsecured Notes outstanding were as follows:

% Rate	Due	2003	2002
		(in thousands)	
4.85	2010 – September 15	$150,000	$-
6.00	2032 – December 31	200,000	200,000
Unamortized Discount		(244)	-
Total		$349,756	$200,000

Notes Payable to Trust was outstanding as follows:

% Rate	Due	2003	2002
		(in thousands)	
8.00	2037 – April 30	$77,320	$-

See Note 16 for discussion of Notes Payable to Trust.

At December 31, 2003, future annual long-term debt payments are as follows:

	Amount (in thousands)
2004	$83,700
2005	50,000
2006	-
2007	1,000
2008	-
Later Years	439,980
Total Principal Amount	574,680
Unamortized Discount	(382)
Total	$574,298

PUBLIC SERVICE COMPANY OF OKLAHOMA
INDEX TO NOTES TO RESPECTIVE FINANCIAL STATEMENTS

The notes to PSO's consolidated financial statements are combined with the notes to respective financial statements for other subsidiary registrants. Listed below are the notes that apply to PSO. The footnotes begin on page L-1.

	Footnote Reference
Organization and Summary of Significant Accounting Policies	Note 1
New Accounting Pronouncements, Extraordinary Items and Cumulative Effect of Accounting Changes	Note 2
Rate Matters	Note 4
Effects of Regulation	Note 5
Commitments and Contingencies	Note 7
Guarantees	Note 8
Sustained Earnings Improvement Initiative	Note 9
Benefit Plans	Note 11
Business Segments	Note 12
Derivatives, Hedging and Financial Instruments	Note 13
Income Taxes	Note 14
Leases	Note 15
Financing Activities	Note 16
Related Party Transactions	Note 17
Jointly Owned Electric Utility Plant	Note 18
Unaudited Quarterly Financial Information	Note 19

INDEPENDENT AUDITORS' REPORT

To the Shareholders and Board of
Directors of Public Service Company of Oklahoma:

We have audited the accompanying balance sheets and statements of capitalization of Public Service Company of Oklahoma as of December 31, 2003 and 2002, and the related statements of income, changes in common shareholder's equity and comprehensive income and cash flows for each of the three years in the period ended December 31, 2003. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. 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, such financial statements present fairly, in all material respects, the financial position of Public Service Company of Oklahoma as of December 31, 2003 and 2002, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2003 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the financial statements, the Company adopted FIN 46, "Consolidation of Variable Interest Entities," effective July 1, 2003.

/s/ Deloitte & Touche LLP

Columbus, Ohio
March 5, 2004

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
SELECTED CONSOLIDATED FINANCIAL DATA

	2003	2002	2001	2000	1999
			(in thousands)		
INCOME STATEMENTS DATA					
Operating Revenues	$1,146,842	$1,084,720	$1,101,326	$1,118,274	$971,527
Operating Expenses	996,706	942,251	955,119	989,996	824,465
Operating Income	150,136	142,469	146,207	128,278	147,062
Nonoperating Items, Net	4,767	(309)	741	3,851	(1,965)
Interest Charges	63,779	59,168	57,581	59,457	58,892
Minority Interest	(1,500)	-	-	-	-
Income Before Extraordinary Item And Cumulative Effect	89,624	82,992	89,367	72,672	86,205
Extraordinary Loss	-	-	-	-	(3,011)
Cumulative Effect of Accounting Changes	8,517	-	-	-	-
Net Income	98,141	82,992	89,367	72,672	83,194
Preferred Stock Dividend Requirements	229	229	229	229	229
Earnings Applicable to Common Stock	$97,912	$82,763	$89,138	$72,443	$82,965
BALANCE SHEETS DATA					
Electric Utility Plant	$3,799,460	$3,596,174	$3,460,764	$3,319,024	$3,231,431
Accumulated Depreciation and Amortization	1,617,846	1,477,875	1,342,003	1,259,509	1,196,629
Net Electric Utility Plant	$2,181,614	$2,118,299	$2,118,761	$2,059,515	$2,034,802
TOTAL ASSETS	$2,581,963	$2,428,138	$2,509,291	$2,855,885	$2,294,375
Common Stock and Paid-in Capital	$380,663	$380,663	$380,663	$380,663	$380,663
Retained Earnings	359,907	334,789	308,915	293,989	283,546
Accumulated Other Comprehensive Income (Loss)	(43,910)	(53,683)	-	-	-
Total Common Shareholder's Equity	$696,660	$661,769	$689,578	$674,652	$664,209
Cumulative Preferred Stock Not Subject to Mandatory Redemption	$4,700	$4,701	$4,701	$4,701	$4,703
Trust Preferred Securities (a)	$-	$110,000	$110,000	$110,000	$110,000
Long-term Debt (b)	$884,308	$693,448	$645,283	$645,963	$541,568
Obligations Under Capital Leases (b)	$21,542	-	-	-	-
TOTAL CAPITALIZATION AND LIABILITIES	$2,581,963	$2,428,138	$2,509,291	$2,855,885	$2,294,375

(a) See Note 16 of the Notes to Respective Financial Statements.
(b) Including portion due within one year.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS

Southwestern Electric Power Company (SWEPCo) is a public utility engaged in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to approximately 439,000 retail customers in our service territory in northeastern Texas, northwestern Louisiana and western Arkansas. As a power pool member with AEP West companies, we share in the revenues and expenses of the power pool's sales to neighboring utilities and power marketers. SWEPCo also sells electric power at wholesale to other utilities, municipalities and electric cooperatives.

Power pool members are compensated for energy delivered to other members based upon the delivering members' incremental cost plus a portion of the savings realized by the purchasing member that avoids the use of more costly alternatives. The revenue and costs for sales to neighboring utilities and power marketers made by AEPSC on behalf of the AEP West companies are shared among the members based upon the relative magnitude of the energy each member provides to make such sales.

Power and gas risk management activities are conducted on our behalf by AEPSC. We share in the revenues and expenses associated with these risk management activities with other AEP registrant subsidiaries excluding AEGCo under existing power pool and system integration agreements. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas. The electricity and gas contracts include physical transactions, over-the-counter options and swaps and exchange traded futures and options. The majority of the physical forward contracts are typically settled by entering into offsetting contracts.

Under our system integration agreement, revenues and expenses from the sales to neighboring utilities, power marketers and other power and gas risk management entities are shared among AEP East and West companies. Sharing in a calendar year is based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger of AEP and CSW. This resulted in an AEP East and West companies' allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year may also be based upon the relative generating capacity of the AEP East and West companies in the event the pre-merger activity level is exceeded. The capacity based allocation mechanism was triggered in June 2003, resulting in an allocation factor of approximately 70% and 30% for the AEP East and West companies, respectively, for the remainder of 2003.

Results of Operations

2003 Compared to 2002

During 2003, Net Income increased $15 million primarily due to an $8 million increase in Operating Income and the adoption of SFAS 143, which resulted in Cumulative Effect of Accounting Changes of $9 million in the first quarter of 2003. Significant fluctuations occurred in revenues, fuel and purchased power due to certain ICR adjustments in 2002; however, income is generally not affected due to the functioning of fuel adjustment clauses in the retail jurisdictions.

Operating Income

Operating Income increased by $8 million primarily due to:

- A $12 million increase in wholesale margins due to an increase in our allocation of overall AEP System sales percentages resulting from increased amounts of off-system sales.
- A $12 million increase in retail base revenues due to increased customers and their average usage, offset in part by milder weather. Cooling and heating degree-days declined 6%.
- A $7 million increase in income from risk management activities.
- A decrease of $16 million in Other Operation expense primarily due to decreases in customer services, outside services and other administrative expenses.

The increase in Operating Income was partially offset by:

- A $9 million decrease in wholesale base margins primarily due to decreased demand from wholesale customers.
- A $4 million decrease in capacity revenues due to the elimination of the requirement under the Texas Restructuring legislation to sell capacity. See Note 6.
- A $21 million increase in Income Taxes due to increases in pre-tax operating income, federal and state tax return and tax accrual adjustments and changes to certain book/tax timing differences accounted for on a flow-through basis.

Other Impacts on Earnings

Nonoperating Income Tax Credit increased by $5 million due to changes in certain book/tax timing differences accounted for on a flow-through basis, changes in consolidated tax savings and tax return and tax accrual adjustments.

Interest Charges increased $5 million primarily due to higher levels of outstanding debt, consolidation of Sabine Mining Company and in financing activity at Dolet Hills.

Minority Interest expense of $2 million is a result of consolidating Sabine Mining Company during the third quarter of 2003, due to the implementation of FIN 46. See Notes 2 and 8 for additional discussion.

Cumulative Effect of Accounting Changes

The Cumulative Effect of Accounting Changes is due to the one-time, after-tax impact of adopting SFAS 143 and implementing the requirements of EITF 02-3 (see Note 2).

2002 Compared to 2001

During 2002, Net Income decreased $6 million primarily resulting from reduced margins from risk management activities. Significant fluctuations occurred in revenues, fuel and purchased power due to certain ICR adjustments in 2002; however, income is generally not affected due to the functioning of fuel adjustment clauses in the retail jurisdictions.

Operating Income

Operating Income decreased by $4 million primarily due to:

- A $4 million decrease in retail base revenues mainly due to decreased KWH sales of 6% resulting from the loss of a large industrial customer in 2002.
- A $15 million decrease in income from risk management activities.
- An increase of $18 million in Other Operation expense primarily due to the acquisition of Dolet Hills Lignite Company.
- A $3 million increase in Depreciation and Amortization due primarily to the Dolet Hills acquisition.

The decrease in Operating Income was partially offset by:

- An increase of $13 million in other revenue primarily from the Dolet Hills Acquisition.
- An increase of $7 million in capacity revenues, due to the requirement under the Texas Restructuring legislation to sell capacity.
- An $8 million decrease in Maintenance expense due to less storm damage and reduced tree trimming expense in 2002.
- A decrease in Income Taxes of $8 million due to a decrease in pre-tax income.

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Current ratings are as follows:

	Moody's	S&P	Fitch
First Mortgage Bonds	A3	BBB	A
Senior Unsecured Debt	Baa1	BBB	A-

In February 2003, Moody's Investors Service (Moody's) completed their review of AEP and its rated subsidiaries. The results of that review included a downgrade of our rating for unsecured debt from A2 to Baa1 and secured debt from A1 to A3. The completion of this review was a culmination of ratings action started during 2002. In March 2003, S&P lowered AEP and our senior unsecured debt and first mortgage bonds ratings from BBB+ to BBB.

Cash Flow

Cash flows for the years ended December 31, 2003, 2002 and 2001 were as follows:

	2003	2002	2001
Cash and cash equivalents at beginning of period	$2,069	$5,415	$1,907
Cash flows from (used for):			
Operating activities	248,094	210,563	169,610
Investing activities	(110,849)	(110,641)	(197,852)
Financing activities	(127,590)	(103,268)	31,750
Net increase (decrease) in cash and cash equivalents	9,655	(3,346)	3,508
Cash and cash equivalents at end of period	$11,724	$2,069	$5,415

Operating Activities

Cash flows from operating activities were $248 million during 2003 primarily due to net income, Accounts Receivables, Accounts Payable and Accrued Taxes.

Investing Activities

Cash spent on investing activities during 2003 were comparable to 2002. In 2003, construction expenditures were primarily related to projects for improved transmission and distribution service reliability.

Financing Activities

Cash flows used for financing activities increased by $24 million during 2003 in comparison to 2002. During 2003 we paid $16 million more in common stock dividends than in 2002. During the first quarter of 2003 we retired $55 million of first mortgage bonds at maturity. In April 2003, we issued $100 million of senior unsecured debt due 2015 at a coupon of 5.375%. In May 2003, one of our mining subsidiaries issued $44 million of notes due in 2011 at a coupon of 4.47%. The loan was used primarily to reduce a note to us with an interest rate of 8.06%. During the fourth quarter of 2003, we had an early redemption of $45 million of first mortgage bonds due in 2023.

Summary Obligation Information

Our contractual obligations include amounts reported on the Consolidated Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes our contractual cash obligations at December 31, 2003:

	Payments Due by Period (in millions)				
Contractual Cash Obligations	Less Than 1 year	2-3 years	4–5 years	After 5 years	Total
Long-term Debt	$142,714	$226,628	$123,263	$391,703	$884,308
Unconditional Purchase Obligations (a)	185,425	329,513	85,800	171,601	772,339
Capital Lease Obligations	4,737	9,174	8,799	4,380	27,090
Noncancellable Operating Leases	5,522	12,864	14,669	17,849	50,904
Total	$338,398	$578,179	$232,531	$585,533	$1,734,641

(a) Represents contractual obligations to purchase coal and natural gas as fuel for electric generation along with related transportation costs.

In connection with reducing the cost of the lignite mining contract for its Henry W. Pirkey Power Plant, we have agreed under certain conditions, to assume the obligations under capital lease obligations and term loan payments of the mining contractor, Sabine Mining Company (Sabine). In the event Sabine defaults under any of these agreements, our total future maximum payment exposure is approximately $58 million with maturity dates ranging from June 2005 to February 2012.

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, we have agreed to provide guarantees of mine reclamation in the amount of approximately $85 million. Since we use self-bonding, the guarantee provides for us to commit to use its resources to complete the reclamation in the event the work is not completed by a third party miner. At December 31, 2003, the cost to reclaim the mine in 2035 is estimated to be approximately $36 million. This guarantee ends upon depletion of reserves estimated at 2035 plus 6 years to complete reclamation.

On July 1, 2003, we consolidated Sabine due to the application of FIN 46 (see Note 2). Upon consolidation, we recorded the assets and liabilities of Sabine ($78 million). Also, after consolidation, we currently record all expenses (depreciation, interest and other operation expense) of Sabine and eliminate Sabine's revenues against our fuel expenses. There is no cumulative effect of an accounting change recorded as a result of the requirement to consolidate, and there is no change in net income due to the consolidation of Sabine.

Significant Factors

See the "Registrants' Combined Management's Discussion and Analysis" section beginning on page M-1 for additional discussion of factors relevant to us.

Quantitative And Qualitative Disclosures About Risk Management Activities

Market Risks

Our risk management policies and procedures are instituted and administered at the AEP consolidated level. See complete discussion within AEP's "Qualitative And Quantitative Disclosures About Risk Management Activities" section. The following tables provide information about our risk management activities' effect on this specific registrant.

MTM Risk Management Contract Net Assets

This table provides detail on changes in our MTM net asset or liability balance sheet position from one period to the next.

MTM Risk Management Contract Net Assets
Year Ended December 31, 2003
(in thousands)

Domestic Power

Beginning Balance December 31, 2002	$4,050
(Gain) Loss from Contracts Realized/Settled During the Period (a)	820
Fair Value of New Contracts When Entered Into During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	(32)
Change in Fair Value Due to Valuation Methodology Changes	-
Effect of EITF 98-10 Rescission (d)	151
Changes in Fair Value of Risk Management Contracts (e)	4,002
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (f)	7,615
Total MTM Risk Management Contract Net Assets, Excluding Cash Flow Hedges	16,606
Net Cash Flow Hedge Contracts (g)	(741)
Ending Balance December 31, 2003	$15,865

(a) "(Gain) Loss from Contracts Realized/Settled During the Period" includes realized gains from risk management contracts and related derivatives that settled during 2003 that were entered into prior to 2003.
(b) The "Fair Value of New Contracts When Entered Into During the Period" represents the fair value of long-term contracts entered into with customers during 2003. The fair value is calculated as of the execution of the contract. Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. The contract prices are valued against market curves associated with the delivery location.
(c) "Net Option Premiums Paid/(Received)" reflects the net option premiums paid/(received) as they relate to unexercised and unexpired option contracts that were entered into in 2003.
(d) See Note 2 "New Accounting Pronouncements, Extraordinary Items and Cumulative Effect of Accounting Changes."
(e) "Changes in Fair Value of Risk Management Contracts" represents the fair value change in the risk management portfolio due to market fluctuations during the current period. Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
(f) "Change in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
(g) "Net Cash Flow Hedge Contracts (pre-tax) are discussed below in Accumulated Other Comprehensive Income (Loss).

Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets

The table presenting maturity and source of fair value of MTM risk management contract net assets provides two fundamental pieces of information:

- The source of fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).
- The maturity, by year, of our net assets/liabilities, giving an indication of when these MTM amounts will settle and generate cash.

Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets
Fair Value of Contracts as of December 31, 2003

	2004	2005	2006	2007	2008	After 2008	Total (c)
			(in thousands)				
Prices Actively Quoted – Exchange Traded Contracts	$384	$(160)	$15	$98	$-	$-	$337
Prices Provided by Other External Sources – OTC Broker Quotes (a)	8,198	2,533	928	585	336	-	12,580
Prices Based on Models and Other Valuation Methods (b)	(970)	776	183	383	800	2,517	3,689
Total	$7,612	$3,149	$1,126	$1,066	$1,136	$2,517	$16,606

(a) "Prices Provided by Other External Sources – OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.

(b) "Prices Based on Models and Other Valuation Methods" is in absence of pricing information from external sources, modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the Modeled category varies by market.

(c) Amounts exclude Cash Flow Hedges.

Cash Flow Hedges Included in Accumulated Other Comprehensive Income (Loss) (AOCI) on the Balance Sheet

The table provides detail on effective cash flow hedges under SFAS 133 included in the balance sheet. The data in the table will indicate the magnitude of SFAS 133 hedges we have in place. (However, given that under SFAS 133 only cash flow hedges are recorded in AOCI, the table does not provide an all-encompassing picture of our hedging activity). The table also includes a roll-forward of the AOCI balance sheet account, providing insight into the drivers of the changes (new hedges placed during the period, changes in value of existing hedges and roll-off of hedges). In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Years Ended December 31, 2003

	Domestic Power (in thousands)
Beginning Balance December 31, 2002	$(48)
Changes in Fair Value (a)	21
Reclassifications from AOCI to Net Income (b)	211
Ending Balance December 31, 2003	$184

(a) "Changes in Fair Value" shows changes in the fair value of derivatives designated as hedging instruments in cash flow hedges during the reporting period not yet reclassified into net income, pending the hedged item's affecting net income. Amounts are reported net of related income taxes.

(b) "Reclassifications from AOCI to Net Income" represents gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into net income during the reporting period. Amounts are reported net of related income taxes above.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is an $853 thousand gain.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Risk Management Contracts

The following table shows the end, high, average, and low market risk as measured by VaR for year-to-date:

December 31, 2003 (in thousands)				December 31, 2002 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$304	$1,182	$495	$118	$155	$474	$170	$34

VaR Associated with Debt Outstanding

The risk of potential loss in fair value attributable to our exposure to interest rates, primarily related to long-term debt with fixed interest rates was $57 million and $70 million at December 31, 2003 and 2002, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period, therefore a near term change in interest rates should not negatively affect our results of operation or consolidated financial position.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2003, 2002 and 2001

	2003	2002	2001
		(in thousands)	
OPERATING REVENUES			
Electric Generation, Transmission and Distribution	$1,077,988	$1,012,421	$1,022,089
Sales to AEP Affiliates	68,854	72,299	79,237
TOTAL	1,146,842	1,084,720	1,101,326
OPERATING EXPENSES			
Fuel for Electric Generation	441,445	388,334	457,613
Purchased Electricity for Resale	34,850	44,119	18,164
Purchased Electricity from AEP Affiliates	47,914	42,022	15,858
Other Operation	173,349	189,024	171,314
Maintenance	70,443	66,855	74,677
Depreciation and Amortization	121,072	122,969	119,543
Taxes Other Than Income Taxes	53,165	55,232	55,834
Income Taxes	54,468	33,696	42,116
TOTAL	996,706	942,251	955,119
OPERATING INCOME	150,136	142,469	146,207
Nonoperating Income	3,978	3,260	4,512
Nonoperating Expenses	2,607	1,797	3,229
Nonoperating Income Tax Expense (Credit)	(3,396)	1,772	542
Interest Charges	63,779	59,168	57,581
Minority Interest	(1,500)	-	-
Income Before Cumulative Effect of Accounting Changes	89,624	82,992	89,367
Cumulative Effect of Accounting Changes (Net of Tax)	8,517	-	-
NET INCOME	98,141	82,992	89,367
Preferred Stock Dividend Requirements	229	229	229
EARNINGS APPLICABLE TO COMMON STOCK	$97,912	$82,763	$89,138

The common stock of SWEPCo is owned by a wholly-owned subsidiary of AEP.

See Notes to Respective Financial Statements beginning on page L-1.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME
For the Years Ended December 31, 2003, 2002 and 2001
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2000	$135,660	$245,003	$293,989	$-	$674,652
Common Stock Dividends			(74,212)		(74,212)
Preferred Stock Dividends			(229)		(229)
TOTAL					600,211
COMPREHENSIVE INCOME					
NET INCOME			89,367		89,367
TOTAL COMPREHENSIVE INCOME					89,367
DECEMBER 31, 2001	$135,660	$245,003	$308,915	$-	$689,578
Common Stock Dividends			(56,889)		(56,889)
Preferred Stock Dividends			(229)		(229)
TOTAL					632,460
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Unrealized Gain on Cash Flow Power Hedges				(48)	(48)
Minimum Pension Liability				(53,635)	(53,635)
NET INCOME			82,992		82,992
TOTAL COMPREHENSIVE INCOME					29,309
DECEMBER 31, 2002	$135,660	$245,003	$334,789	$(53,683)	$661,769
Common Stock Dividends			(72,794)		(72,794)
Preferred Stock Dividends			(229)		(229)
TOTAL					588,746
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Unrealized Gain on Cash Flow Hedges				232	232
Minimum Pension Liability				9,541	9,541
NET INCOME			98,141		98,141
TOTAL COMPREHENSIVE INCOME					107,914
DECEMBER 31, 2003	$135,660	$245,003	$359,907	$(43,910)	$696,660

See Notes to Respective Financial Statements beginning on page L-1.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2003 and 2002

	2003	2002
	(in thousands)	
ELECTRIC UTILITY PLANT		
Production	$1,622,498	$1,503,722
Transmission	615,158	575,003
Distribution	1,078,368	1,063,564
General	423,427	378,130
Construction Work in Progress	60,009	75,755
TOTAL	3,799,460	3,596,174
Accumulated Depreciation and Amortization	1,617,846	1,477,875
TOTAL - NET	2,181,614	2,118,299
OTHER PROPERTY AND INVESTMENTS		
Non-Utility Property, Net	3,808	4,203
Other Investments	4,710	1,775
TOTAL	8,518	5,978
CURRENT ASSETS		
Cash and Cash Equivalents	11,724	2,069
Advances to Affiliates	66,476	-
Accounts Receivable:		
Customers	41,474	61,478
Affiliated Companies	10,394	19,253
Miscellaneous	4,682	881
Allowance for Uncollectible Accounts	(2,093)	(2,128)
Fuel Inventory	63,881	61,741
Materials and Supplies	33,775	33,539
Regulatory Asset for Under-recovered Fuel Costs	11,394	2,865
Risk Management Assets	19,715	4,388
Margin Deposits	5,123	105
Prepayments and Other	19,078	17,746
TOTAL	285,623	201,937
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	3,235	19,855
Unamortized Loss on Required Debt	19,331	17,031
Other	15,859	12,347
Long-term Risk Management Assets	12,178	5,119
Deferred Charges	55,605	47,572
TOTAL	106,208	101,924
TOTAL ASSETS	$2,581,963	$2,428,138

See Notes to Respective Financial Statements beginning on page L-1.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
December 31, 2003 and 2002

	2003	2002
	(in thousands)	
CAPITALIZATION		
Common Shareholder's Equity:		
Common Stock – $18 Par Value:		
Authorized – 7,600,000 Shares		
Outstanding – 7,536,640 Shares	$135,660	$135,660
Paid-in Capital	245,003	245,003
Retained Earnings	359,907	334,789
Accumulated Other Comprehensive Income (Loss)	(43,910)	(53,683)
Total Common Shareholder's Equity	696,660	661,769
Cumulative Preferred Stock Not Subject to Mandatory Redemption	4,700	4,701
Total Shareholder's Equity	701,360	666,470
SWEPCo – Obligated, Mandatorily Redeemable Preferred Securities of Subsidiary Trust Holding Solely Junior Subordinated Debentures of SWEPCo	-	110,000
Long-term Debt	741,594	637,853
TOTAL	1,442,954	1,414,323
Minority Interest	1,367	-
CURRENT LIABILITIES		
Long-term Debt Due Within One Year	142,714	55,595
Advances from Affiliates	-	23,239
Accounts Payable:		
General	37,646	62,139
Affiliated Companies	35,138	58,773
Customer Deposits	24,260	20,110
Taxes Accrued	28,691	19,081
Interest Accrued	16,852	17,051
Risk Management Liabilities	11,361	3,724
Obligations Under Capital Leases	3,159	-
Regulatory Liability for Over-recovered Fuel	4,178	17,226
Other	53,753	34,565
TOTAL	357,752	311,503
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	349,064	341,064
Long-term Risk Management Liabilities	4,667	1,806
Reclamation Reserve	16,512	13,826
Regulatory Liabilities:		
Asset Removal Costs	236,409	-
Deferred Investment Tax Credits	39,864	44,190
Excess Earnings	2,600	3,700
Other	18,779	3,394
Asset Retirement Obligations	8,429	-
Obligations Under Capital Leases	18,383	-
Deferred Credits and Other	85,183	294,332
TOTAL	779,890	702,312
Commitments and Contingencies (Note 7)		
TOTAL CAPITALIZATION AND LIABILITIES	$2,581,963	$2,428,138

See Notes to Respective Financial Statements beginning on page L-1.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2003, 2002 and 2001

	2003	2002	2001
		(in thousands)	
OPERATING ACTIVITIES			
Net Income	$98,141	$82,992	$89,367
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:			
Depreciation and Amortization	121,072	122,969	119,543
Deferred Income Taxes	9,942	(3,134)	(31,396)
Deferred Investment Tax Credits	(4,326)	(4,524)	(4,453)
Cumulative Effect of Accounting Changes	(8,517)	-	-
Mark-to-Market of Risk Management Contracts	(12,403)	(1,151)	(10,695)
Changes in Certain Assets and Liabilities:			
Accounts Receivable, Net	27,527	(24,371)	(11,447)
Fuel, Materials and Supplies	4,165	(10,541)	(19,578)
Accounts Payable	(51,687)	11,633	(34,489)
Taxes Accrued	8,446	(17,441)	25,298
Fuel Recovery	(21,577)	17,713	34,423
Change in Other Assets	16,268	24,257	1,323
Change in Other Liabilities	61,043	12,161	11,714
Net Cash Flows From Operating Activities	248,094	210,563	169,610
INVESTING ACTIVITIES			
Construction Expenditures	(121,124)	(111,775)	(111,725)
Investment in Mining Operations	-	-	(85,716)
Proceeds from Sale of Assets and Other	10,275	1,134	(411)
Net Cash Flows Used For Investing Activities	(110,849)	(110,641)	(197,852)
FINANCING ACTIVITIES			
Issuance of Long-term Debt	254,630	198,573	-
Retirement of Long-term Debt	(219,482)	(150,595)	(595)
Change in Advances to/from Affiliates, Net	(89,715)	(94,128)	106,786
Dividends Paid on Common Stock	(72,794)	(56,889)	(74,212)
Dividends Paid on Cumulative Preferred Stock	(229)	(229)	(229)
Net Cash Flows From (Used For) Financing Activities	(127,590)	(103,268)	31,750
Net Increase (Decrease) in Cash and Cash Equivalents	9,655	(3,346)	3,508
Cash and Cash Equivalents at Beginning of Period	2,069	5,415	1,907
Cash and Cash Equivalents at End of Period	$11,724	$2,069	$5,415

SUPPLEMENTAL DISCLOSURE:
Cash paid for interest net of capitalized amounts was $57,775,000, $49,008,000 and $51,126,000 and for income taxes was $33,616,000, $60,451,000 and $49,901,000 in 2003, 2002 and 2001, respectively.

Noncash activity in 2003 included an increase in assets and liabilities of $78 million resulting from the consolidation of Sabine Mining Company (see Note 2).

See Notes to Respective Financial Statements beginning on page L-1.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF CAPITALIZATION
December 31, 2003 and 2002

						2003	2002
						(in thousands)	
COMMON SHAREHOLDER'S EQUITY						$696,660	$661,769
PREFERRED STOCK: $100 par value – authorized shares 1,860,000							
Series	Call Price December 31, 2003	Number of Shares Redeemed Year Ended December 31, 2003	2002	2001	Shares Outstanding December 31, 2003		
Not Subject to Mandatory Redemption:							
4.28%	$103.90	-	-	-	7,386	740	740
4.65%	$102.75	-	-	-	1,907	190	190
5.00%	$109.00	12	-	-	37,703	3,770	3,771
Total Preferred Stock						4,700	4,701
TRUST PREFERRED SECURITIES:							
SWEPCo-Obligated, Mandatorily Redeemable Preferred Securities of Subsidiary Trust Holding Solely Junior Subordinated Debentures of SWEPCo, 7.875%, due April 30, 2037 (a)						-	110,000
LONG-TERM DEBT (See Schedule of Long-term Debt):							
First Mortgage Bonds						215,712	315,420
Installment Purchase Contracts						178,531	179,183
Senior Unsecured Notes						299,216	198,845
Notes Payable to Trust (a)						113,009	-
Notes Payable						77,840	-
Less Portion Due Within One Year						(142,714)	(55,595)
Long-term Debt Excluding Portion Due Within One Year						741,594	637,853
TOTAL CAPITALIZATION						$1,442,954	$1,414,323

(a) See Note 16 for Notes Payable to Trust.

See Notes to Respective Financial Statements beginning on page L-1.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
SCHEDULE OF LONG-TERM DEBT
December 31, 2003 and 2002

First Mortgage Bonds outstanding were as follows:

% Rate	Due	2003	2002
		(in thousands)	
6-5/8	2003 – February 1	$-	$55,000
7-3/4	2004 – June 1	40,000	40,000
6.20	2006 – November 1	5,360	5,505
6.20	2006 – November 1	1,000	1,000
7.00	2007 – September 1	90,000	90,000
7-1/4	2023 – July 1	-	45,000
6-7/8	2025 – October 1 (a)	80,000	80,000
Unamortized Discount		(648)	(1,085)
Total		$215,712	$315,420

(a) This bond was redeemed on March 1, 2004 and has been classified for payment in 2004.

First Mortgage Bonds are secured by a first mortgage lien on electric utility plant. The indenture, as supplemented, relating to the first mortgage bonds contains maintenance and replacement provisions requiring the deposit of cash or bonds with the trustee, or in lieu thereof, certification of unfunded property additions.

Installment Purchase Contracts have been entered into in connection with the issuance of pollution control revenue bonds by governmental authorities as follows:

	% Rate	Due	2003	2002
			(in thousands)	
Desoto County:				
	7.60	2019 – January 1	$53,500	$53,500
Sabine River Authority of Texas:				
	6.10	2018 – April 1	81,700	81,700
Titus County:				
	6.90	2004 – November 1	12,290	12,290
	6.00	2008 – January 1	12,170	12,620
	8.20	2011 – August 1	17,125	17,125
	Unamortized Premium		1,746	1,948
	Total		$178,531	$179,183

Under the terms of the installment purchase contracts, SWEPCo is required to pay amounts sufficient to enable the payment of interest on and the principal of (at stated maturities and upon mandatory redemptions) related pollution control revenue bonds issued to finance the construction of pollution control facilities at certain plants.

Senior Unsecured Notes outstanding were as follows:

%Rate	Due	2003	2002
		(in thousands)	
4.50	2005 – July 1	$200,000	$200,000
5.38	2015 – April 15	100,000	-
Unamortized Discount		(784)	(1,155)
Total		$299,216	$198,845

Notes Payable to Trust was outstanding as follows:

%Rate	Due	2003	2002
		(in thousands)	
5.25% (a)	2043 – October 1	$113,403	$-
Unamortized Discount		(394)	-
Total		$113,009	$-

(a) The 5.25% interest rate is thru September 10, 2008 after which they become floating rate bonds if the notes are not remarketed.

See Note 16 for discussion of Notes Payable to Trust.

Notes Payable outstanding were as follows:

%Rate	Due	2003	2002
		(in thousands)	
Sabine Mining Company (a):			
6.36	2007 – February 22	$4,000	$-
(b)	2008 – June 30	13,500	-
7.03	2012 – February 22	20,000	-
Dolet Hills Lignite Company:			
4.47	2011 – May 16	40,340	-
Total		$77,840	$-

(a) Sabine Mining Company was consolidated during the third quarter of 2003 due to the implementation of FIN 46.
(b) A floating interest rate is determined quarterly. The rate on December 31, 2003 was 1.54%.

At December 31, 2003 future annual long-term debt payments are as follows:

	Amount (in thousands)
2004	$142,714
2005	210,424
2006	16,204
2007	104,862
2008	18,401
Later Years	391,783
Total Principal Amount	884,388
Unamortized Discount	(80)
Total	$884,308

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
INDEX TO NOTES TO RESPECTIVE FINANCIAL STATEMENTS

The notes to SWEPCo's consolidated financial statements are combined with the notes to respective financial statements for other subsidiary registrants. Listed below are the notes that apply to SWEPCo. The footnotes begin on page L-1.

	Footnote Reference
Organization and Summary of Significant Accounting Policies	Note 1
New Accounting Pronouncements, Extraordinary Items and Cumulative Effect of Accounting Changes	Note 2
Goodwill and Other Intangible Assets	Note 3
Rate Matters	Note 4
Effects of Regulation	Note 5
Customer Choice and Industry Restructuring	Note 6
Commitments and Contingencies	Note 7
Guarantees	Note 8
Sustained Earnings Improvement Initiative	Note 9
Acquisitions, Dispositions, Impairments, Assets Held for Sale and Assets Held and Used	Note 10
Benefit Plans	Note 11
Business Segments	Note 12
Derivatives, Hedging and Financial Instruments	Note 13
Income Taxes	Note 14
Leases	Note 15
Financing Activities	Note 16
Related Party Transactions	Note 17
Jointly Owned Electric Utility Plant	Note 18
Unaudited Quarterly Financial Information	Note 19

INDEPENDENT AUDITORS' REPORT

To the Shareholders and Board of
Directors of Southwestern Electric Power Company:

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Southwestern Electric Power Company Consolidated as of December 31, 2003 and 2002, and the related consolidated statements of income, changes in common shareholder's equity and comprehensive income and cash flows for each of the three years in the period ended December 31, 2003. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. 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, such consolidated financial statements present fairly, in all material respects, the financial position of Southwestern Electric Power Company Consolidated as of December 31, 2003 and 2002, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2003 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, the Company adopted SFAS 143, "Accounting for Asset Retirement Obligations," effective January 1, 2003.

As discussed in Note 2 to the consolidated financial statements, the Company adopted FIN 46, "Consolidation of Variable Interest Entities," effective July 1, 2003.

/s/ Deloitte & Touche LLP

Columbus, Ohio
March 5, 2004

NOTES TO RESPECTIVE FINANCIAL STATEMENTS

The notes to respective financial statements that follow are a combined presentation for AEP's subsidiary registrants. The following list indicates the registrants to which the footnotes apply:

1.	Organization and Summary of Significant Accounting Policies	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
2.	New Accounting Pronouncements, Extraordinary Items and Cumulative Effect of Accounting Changes	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
3.	Goodwill and Other Intangible Assets	SWEPCo
4.	Rate Matters	APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
5.	Effects of Regulation	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
6.	Customer Choice and Industry Restructuring	APCo, CSPCo, I&M, OPCo, SWEPCo, TCC, TNC
7.	Commitments and Contingencies	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
8.	Guarantees	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
9.	Sustained Earnings Improvement Initiative	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
10.	Acquisitions, Dispositions, Impairments, Assets Held for Sale and Assets Held and Used	APCo, CSPCo, I&M, KPCo, OPCo, SWEPCo, TCC, TNC
11.	Benefit Plans	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
12.	Business Segments	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
13.	Derivatives, Hedging and Financial Instruments	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
14.	Income Taxes	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
15.	Leases	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
16.	Financing Activities	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
17.	Related Party Transactions	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
18.	Jointly Owned Electric Utility Plant	CSPCo, PSO, SWEPCo, TCC, TNC
19.	Unaudited Quarterly Financial Information	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
20.	Subsequent Events (Unaudited)	TCC

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

The principal business conducted by AEP's ten domestic electric utility operating companies is the generation, transmission and distribution of electric power. These companies are subject to regulation by the FERC under the Federal Power Act and maintain accounts in accordance with FERC and other regulatory guidelines. These companies are subject to further regulation with regard to rates and other matters by state regulatory commissions.

With the exception of AEGCo, AEP's registrant subsidiaries engage in wholesale marketing and risk management activities in the United States. In addition, I&M provides barging services to both affiliated and nonaffiliated companies.

See Note 10 for additional information regarding asset impairments and assets and liabilities held for sale related to our Texas generation plants.

Certain previously reported amounts have been reclassified to conform to current classifications with no effect on net income or shareholders' equity.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rate Regulation

AEP and its subsidiaries are subject to regulation by the SEC under the PUHCA. The rates charged by the utility subsidiaries are approved by the FERC and the state utility commissions. The FERC regulates wholesale electricity operations and transmission rates and the state commissions regulate retail rates.

Principles of Consolidation

The consolidated financial statements for APCo, CSPCo, I&M, OPCO, SWEPCo and TCC include the registrant and its wholly-owned subsidiaries and/or substantially controlled variable interest entities. Intercompany items are eliminated in consolidation. Equity investments not substantially controlled that are 50% or less owned are accounted for using the equity method of accounting; equity earnings are included in Nonoperating Income.

Accounting for the Effects of Cost-Based Regulation

As cost-based rate-regulated electric public utility companies, the consolidated financial statements reflect the actions of regulators that result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated. Regulatory assets (deferred expenses) and regulatory liabilities (future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues. The following subsidiaries discontinued the application of SFAS 71 for the generation portion of their business as follows: in Ohio by OPCo and CSPCo in September 2000, in Virginia and West Virginia by APCo in June 2000, in Texas by TCC, TNC, and SWEPCo in September 1999, in Arkansas by SWEPCo in September 1999 and in the FERC jurisdiction for TNC in December 2003. During 2003, APCo reapplied SFAS 71 for West Virginia and SWEPCo reapplied SFAS 71 for Arkansas.

Use of Estimates

The preparation of these 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 amounts reported in the financial statements and accompanying notes. These estimates include but are not limited to inventory valuation, allowance for doubtful accounts, unbilled electricity revenue, values of long-term energy contracts, the effects of regulation, long-lived asset recovery, the effects of contingencies and certain assumptions made in accounting for pension benefits. Actual results could differ from those estimates.

Property, Plant and Equipment

Domestic electric utility property, plant and equipment are stated at original purchase cost. Property, plant and equipment of the non-regulated operations and other investments are stated at their fair market value at acquisition (or as adjusted for any applicable impairments) plus the original cost of property acquired or constructed since the acquisition, less disposals. Additions, major replacements and betterments are added to the plant accounts. For cost-based rate-regulated operations, retirements from the plant accounts and associated removal costs, net of salvage, are deducted from accumulated depreciation. For non-regulated operations, retirements from the plant accounts and associated salvage are deducted from accumulated depreciation and removal costs are charged to expense. The costs of labor, materials and overhead incurred to operate and maintain plant are included in operating expenses. Assets are tested for impairment as required under SFAS 144 (see Note 10).

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

AFUDC represents the estimated cost of borrowed and equity funds used to finance construction projects that is capitalized and recovered through depreciation over the service life of domestic regulated electric utility plant. For non-regulated operations, interest is capitalized during construction in accordance with SFAS 34, "Capitalization of Interest Costs." Capitalized interest is also recorded for domestic generating assets in Ohio, Texas and Virginia, effective with the discontinuance of SFAS 71 regulatory accounting. The amounts of AFUDC and interest capitalized were not material in 2003, 2002 and 2001.

Depreciation, Depletion and Amortization

We provide for depreciation of property, plant and equipment on a straight-line basis over the estimated useful lives of property, excluding coal-mining properties, through the use of composite rates by functional class. The following table provides the annual composite depreciation rates by functional class generally used by the AEP registrant subsidiaries for the year 2003:

	Nuclear	Steam	Hydro	Transmission	Distribution	General
AEGCo	-%	3.5%	-%	-%	-%	16.7%
APCo	-	3.3	2.7	2.2	3.3	9.3
CSPCo	-	3.0	-	2.3	3.6	9.9
I&M	3.4	4.6	3.4	1.9	4.2	11.8
KPCo	-	3.8	-	1.7	3.5	7.1
OPCo	-	2.8	2.7	2.3	4.0	10.5
PSO	-	2.7	-	2.3	3.4	9.7
SWEPCo	-	3.3	-	2.8	3.6	8.0
TCC	2.5	2.3	1.9	2.3	3.5	8.1
TNC	-	2.6	-	3.1	3.3	10.2

The annual composite depreciation rates by functional class generally used by the AEP registrant subsidiaries for the years 2002 and 2001 were as follows:

	Nuclear	Steam	Hydro	Transmission	Distribution	General
AEGCo	-%	3.5%	-%	-%	-%	2.8%
APCo	-	3.4	2.9	2.2	3.3	3.1
CSPCo	-	3.2	-	2.3	3.6	3.2
I&M	3.4	4.5	3.4	1.9	4.2	3.8
KPCo	-	3.8	-	1.7	3.5	2.5
OPCo	-	3.4	2.7	2.3	4.0	2.7
PSO	-	2.7	-	2.3	3.4	6.3
SWEPCo	-	3.4	-	2.7	3.6	4.7
TCC	2.5	2.6	1.9	2.3	3.5	4.0
TNC	-	2.8	-	3.1	3.3	6.8

We provide for depreciation, depletion and amortization of coal-mining assets over each asset's estimated useful life or the estimated life of each mine, whichever is shorter, using the straight-line method for mining structures and equipment. We use either the straight-line method or the units-of-production method to amortize mine development costs and deplete coal rights based on estimated recoverable tonnages. We include these costs in the cost of coal charged to fuel expense. Average amortization rates for coal rights and mine development costs related to SWEPCo were $0.41 per ton in 2003, 2002 and 2001 and related to OPCo were $3.46 per ton in 2001. In 2001, OPCo sold coal mines in Ohio and West Virginia.

Valuation of Non-Derivative Financial Instruments

The book values of Cash and Cash Equivalents, Accounts Receivable, Short-term Debt and Accounts Payable approximate fair value because of the short-term maturity of these instruments. The book value of the pre-April 1983 spent nuclear fuel disposal liability for I&M approximates the best estimate of its fair value.

Cash and Cash Equivalents

Cash and cash equivalents include temporary cash investments with original maturities of three months or less.

Inventory

Except for PSO, TCC and TNC, the regulated domestic utility companies value fossil fuel inventories using a weighted average cost method. PSO, TCC and TNC, utilize the LIFO method to value fossil fuel inventories. For those domestic utilities whose generation is unregulated, inventory of coal and oil is carried at the lower of cost or market. Coal mine inventories are also carried at the lower of cost or market. Materials and supplies inventories are carried at average cost.

Accounts Receivable

Customer accounts receivable primarily includes receivables from wholesale and retail energy customers, receivables from energy contract counterparties related to our risk management activities and customer receivables primarily related to other revenue-generating activities.

Revenue is recognized from electric power sales when power is delivered to customers. To the extent that deliveries have occurred but a bill has not been issued, AEP and its registrant subsidiaries accrue and recognize, as Accrued Unbilled Revenues, an estimate of the revenues for energy delivered since the latest billings.

AEP Credit, Inc. factors accounts receivable for certain registrant subsidiaries. These subsidiaries include CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in all of its regulatory jurisdictions, only a portion of APCo's accounts receivable are sold to AEP Credit. AEP Credit has a sale of receivables agreement with banks and commercial paper conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires to the commercial paper conduits and banks and receives cash. This transaction constitutes a sale of receivables in accordance with SFAS 140, allowing the receivables to be taken off of the company's balance sheet. See Note 16 for further details.

Deferred Fuel Costs

The cost of fuel consumed is charged to expense when the fuel is burned. Where applicable under governing state regulatory commission retail rate orders, fuel cost over-recoveries (the excess of fuel revenues billed to ratepayers over fuel costs incurred) are deferred as regulatory liabilities and under-recoveries (the excess of fuel costs incurred over fuel revenues billed to ratepayers) are deferred as regulatory assets. These deferrals are amortized when refunded or billed to customers in later months with the regulator's review and approval. The amounts of over-recovery or under-recovery can also be affected by actions of regulators. When these actions become probable we adjust our deferrals to recognize these probable outcomes. For the Texas companies, TCC & TNC, their deferred fuel balances will be included in their 2004 True Up Proceeding (see Note 6 "Customer Choice and Industry Restructuring"). See Note 5 "Effects of Regulation" for the amount of deferred fuel costs by registrant subsidiary.

In general, changes in fuel costs in Kentucky for KPCo, the SPP area of Texas, Louisiana and Arkansas for SWEPCo, Oklahoma for PSO and Virginia for APCo are timely reflected in rates through the fuel cost adjustment clauses in place in those states. Where fuel clauses have been eliminated due to the transition to market pricing, (Ohio effective January 1, 2001 and in the Texas ERCOT area effective January 1, 2002) changes in fuel costs impact earnings. In other state jurisdictions, (Indiana, Michigan and West Virginia) where fuel clauses have been frozen or suspended for a period of years, fuel cost changes have also impacted earnings. The Michigan fuel clause suspension ended December 31, 2003, and the Indiana freeze is scheduled to end on March 1, 2004. See Note 4, "Rate Matters" and Note 6, "Customer Choice and Industry Restructuring" for further information about fuel recovery.

Revenue Recognition

Regulatory Accounting

The consolidated financial statements of the registrant subsidiary companies with cost-based rate-regulated operations (I&M, KPCo, PSO, and a portion of APCo, OPCo, CSPCo, TCC, TNC and SWEPCo), reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate regulated. In accordance with SFAS 71, regulatory assets (deferred expenses to be recovered in the future) and regulatory liabilities (deferred future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues in the same accounting period and by matching income with its passage to customers through regulated revenues in the same accounting period. Regulatory liabilities (unrealized gains) or regulatory assets (unrealized losses) are also recorded for changes in the fair value of physical and financial contracts that meet the definition of a derivative as defined in SFAS 133 and are subject to the regulated ratemaking process.

When regulatory assets are probable of recovery through regulated rates, certain registrant subsidiaries record them as assets on the balance sheet. Registrant subsidiaries test for probability of recovery whenever new events occur, for example a regulatory commission order or passage of new legislation. If registrant subsidiaries determine that recovery of a regulatory asset is no longer probable, they write off that regulatory asset as a charge against net income. A write off of regulatory assets may also reduce future cash flows since there may be no recovery through regulated rates.

Traditional Electricity Supply and Delivery Activities

Revenues are recognized on the accrual or settlement basis for normal retail and wholesale electricity supply sales and electricity transmission and distribution delivery services. The revenues are recognized and recorded when the energy is delivered to the customer and include estimated unbilled as well as billed amounts. In general, expenses are recorded when purchased electricity is received and when expenses are incurred.

Energy Marketing and Risk Management Activities

Registrant subsidiaries engage in wholesale electricity, natural gas and coal marketing and risk management activities. Effective in October 2002, these activities were focused on wholesale markets where registrant subsidiaries own assets. Registrant subsidiaries activities include the purchase and sale of energy under forward contracts at fixed and variable prices and the buying and selling of financial energy contracts which include exchange traded futures and options, and over-the-counter options and swaps. Prior to October 2002, registrant subsidiaries recorded wholesale marketing and risk management activities using the mark-to-market method of accounting.

In October 2002, EITF 02-3 precluded mark-to-market accounting for risk management contracts that were not derivatives pursuant to SFAS 133. Registrant subsidiaries implemented this standard for all non-derivative wholesale and risk management transactions occurring on or after October 25, 2002. For non-derivative risk management transactions entered into prior to October 25, 2002, registrant subsidiaries implemented this standard on January 1, 2003 and reported the effects of implementation as a cumulative effect of an accounting change.

After January 1, 2003, registrant subsidiaries use mark-to-market accounting for wholesale marketing and risk management transactions that are derivatives unless the derivative is designated for hedge accounting or the normal purchase and sale exemption. Revenues and expenses are recognized from wholesale marketing and risk management transactions that are not derivatives when the commodity is delivered.

See discussion of EITF 02-3 and rescission of EITF 98-10 in Note 2.

All of the registrant subsidiaries except AEGCo participate in wholesale marketing and risk management activities in electricity and gas. For I&M, KPCo, PSO and a portion of TNC and SWEPCo, when the contract settles the total gain or loss is realized in revenues. Where the revenues are recorded on the income statement depends on whether the contract is subject to the regulated ratemaking process. For contracts subject to the regulated ratemaking process the total gain or loss realized for sales and the cost of purchased energy are included in revenues on a net basis. Prior to settlement, changes in the fair value of physical and financial forward sale and purchase contracts subject to the regulated ratemaking process are deferred as regulatory liabilities (gains) or regulatory assets (losses). For contracts not subject to the ratemaking process only the difference between the accumulated unrealized net gains or losses recorded in prior periods and the cash proceeds are recognized in the income statement as nonoperating income. Prior to settlement, changes in the fair value of physical and financial forward sale and purchase contracts not subject to the ratemaking process are included in nonoperating income on a net basis. Unrealized mark-to-market gains and losses are included in the balance sheets as Risk Management Assets or Liabilities as appropriate.

For APCo, CSPCo and OPCo, depending on whether the delivery point for the electricity is in the traditional marketing area or not determines where the contract is reported in the income statement. Physical forward risk management sale and purchase contracts with delivery points in the traditional marketing area are included in revenues on a net basis. Prior to settlement, changes in the fair value of physical forward sale and purchase contracts in the traditional marketing area are also included in revenues on a net basis. Physical forward sale and purchase contracts for delivery outside of the traditional marketing area are included in nonoperating income when the contract settles. Prior to settlement, changes in the fair value of physical forward sale and purchase contracts with delivery points outside of the traditional marketing area are included in nonoperating income on a net basis.

Accounting for Derivative Instruments

For derivative contracts that are not designated as hedges or normal purchase and sale transactions registrant subsidiaries recognize unrealized gains and losses prior to settlement based on changes in fair value during the period in our results of operations. When registrant subsidiaries settle mark-to-market derivative contracts and realize gains and losses, registrant subsidiaries reverse previously recorded unrealized gains and losses from mark-to-market valuations.

Certain derivative instruments are designated as a hedge of a forecasted transaction or future cash flow (cash flow hedge) or as a hedge of a recognized asset, liability or firm commitment (fair value hedge). The gains or losses on derivatives designated as fair value hedges are recognized in Revenues in the Consolidated Statement of Operations in the period of change together with the offsetting losses or gains on the hedged item attributable to the risks being hedged. For derivatives designated as cash flow hedges, the effective portion of the derivative's gain or loss is initially reported as a component of Accumulated Other Comprehensive Income and subsequently reclassified into Revenues in the Consolidated Statement of Operations when the forecasted transaction affects earnings. The ineffective portion of the gain or loss is recognized in Revenues in the Consolidated Statement of Operations immediately (see Note 13).

Registrant subsidiaries measure the fair values of derivative instruments and hedge instruments accounted for using mark-to-market accounting based on exchange prices and broker quotes. If a quoted market price is not available, registrant subsidiaries estimate the fair value based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data, and other assumptions. Registrant subsidiaries reduce fair values by estimated valuation adjustments for items such as discounting, liquidity and credit quality. There are inherent risks related to the underlying assumptions in models used to fair value open long-term derivative contracts. Registrant subsidiaries have independent controls to evaluate the reasonableness of our valuation models. However, energy markets, especially

electricity markets, are imperfect and volatile. Unforeseen events can and will cause reasonable price curves to differ from actual prices throughout a contract's term and at the time a contract settles. Therefore, there could be significant adverse or favorable effects on future results of operations and cash flows if market prices are not consistent with our approach at estimating current market consensus for forward prices in the current period. This is particularly true for long-term contracts.

Registrant subsidiaries recognize all derivative instruments at fair value in our balance sheets as either Risk Management Assets or Risk Management Liabilities. Registrant subsidiaries do not consider contracts that have been elected normal purchase or normal sale under SFAS 133 to be derivatives. Unrealized and realized gains and losses on all derivative instruments are ultimately included in revenues in the income statement on a net basis.

Debt Instrument Hedging and Related Activities

In order to mitigate the risks of market price and interest rate fluctuations, registrant subsidiaries enter into contracts to manage the exposure to unfavorable changes in the cost of debt to be issued. These anticipatory hedges are entered into in order to manage the change in interest rates between the time a debt offering is initiated and the issuance of the debt (usually a period of 60 days). Gains or losses from these transactions are deferred and amortized over the life of the debt issuance with the amortization included in interest charges. There were no such forward contracts outstanding at December 31, 2003 or 2002.

Levelization of Nuclear Refueling Outage Costs

In order to match costs with regulated revenues, incremental operation and maintenance costs associated with periodic refueling outages at I&M's Cook Plant are deferred and amortized over the period beginning with the commencement of an outage and ending with the beginning of the next outage.

Maintenance Costs

Maintenance costs are expensed as incurred. If it becomes probable that registrant subsidiaries will recover specifically incurred costs through future rates a regulatory asset is established to match the expensing of maintenance costs with their recovery in cost-based regulated revenues.

Income Taxes and Investment Tax Credits

Registrant Subsidiaries use the liability method of accounting for income taxes. Under the liability method, deferred income taxes are provided for all temporary differences between the book cost and tax basis of assets and liabilities which will result in a future tax consequence.

The flow-through method of accounting for temporary differences is reflected in regulated revenues (that is, when deferred taxes are not included in the cost of service for determining regulated rates for electricity), deferred income taxes are recorded and related regulatory assets and liabilities are established to match the regulated revenues and tax expense.

Investment tax credits have been accounted for under the flow-through method except where regulatory commissions have reflected investment tax credits in the rate-making process on a deferral basis. Investment tax credits that have been deferred are being amortized over the life of the regulated plant investment.

Excise Taxes

Registrant subsidiaries, as agents for some state and local governments collect from customers certain excise taxes levied by those state or local governments on our customers. We do not record these taxes as revenue or expense.

Debt and Preferred Stock

Gains and losses from the reacquisition of debt used to finance domestic regulated electric utility plant are generally deferred and amortized over the remaining term of the reacquired debt in accordance with their rate-

making treatment unless the debt is refinanced. If the reacquired debt, associated with the regulated business, is refinanced, the reacquisition costs attributable to the portions of the business that are subject to cost based regulatory accounting are generally deferred and amortized over the term of the replacement debt consistent with its recovery in rates. We report gains and losses on the reacquisition of debt for operations that are not subject to cost-based rate regulation in Nonoperating Income or Nonoperating Expenses.

Debt discount or premium and debt issuance expenses are deferred and amortized utilizing the effective interest rate method over the term of the related debt. The amortization expense is included in interest charges.

Where reflected in rates, redemption premiums paid to reacquire preferred stock of certain domestic utility subsidiaries are included in paid-in capital and amortized to retained earnings commensurate with their recovery in rates. The excess of par value over costs of preferred stock reacquired is credited to paid-in capital and amortized to retained earnings consistent with the timing of its inclusion in rates in accordance with SFAS 71.

Goodwill and Intangible Assets

In the first quarter of fiscal 2002, AEP's registrant subsidiaries adopted SFAS No. 142, "Goodwill and Other Intangible Assets" which revises the accounting for purchased goodwill and other intangible assets. Under SFAS No. 142, purchased goodwill and intangible assets with indefinite lives are no longer amortized, but instead tested for impairment at least annually. Intangible assets with finite lives, requires that they be amortized over their respective estimated lives to the estimated residual values. The AEP registrant subsidiaries have no recorded goodwill and intangible assets with indefinite lives as of December 31, 2003 and 2002. SWEPCo is the only AEP registrant with an intangible asset with a finite life on its books. See Note 3 for further information about SWEPCo's intangible asset.

Nuclear Trust Funds

Nuclear decommissioning and spent nuclear fuel trust funds represent funds that regulatory commissions have allowed us to collect through rates to fund future decommissioning and spent fuel disposal liabilities. By rules or orders, the state jurisdictional commissions (Indiana, Michigan and Texas) and the FERC have established investment limitations and general risk management guidelines. In general, limitations include:

- Acceptable investments (rated investment grade or above)
- Maximum percentage invested in a specific type of investment
- Prohibition of investment in obligations of the applicable company or its affiliates

Trust funds are maintained for each regulatory jurisdiction and managed by investment managers external to AEP subsidiaries, who must comply with the guidelines and rules of the applicable regulatory authorities. The trust assets are invested in order to optimize the after-tax earnings of the trust, giving consideration to liquidity, risk, diversification, and other prudent investment objectives.

Securities held in trust funds for decommissioning nuclear facilities and for the disposal of spent nuclear fuel are included in Nuclear Decommissioning and Spent Nuclear Fuel Disposal Trust Funds for amounts relating to the Cook Plant and are included in Assets Held for Sale for amounts relating to the Texas Plants. See "Assets Held for Sale" section of Note 10 for further information regarding the Texas Plants. These securities are recorded at market value. Securities in the trust funds have been classified as available-for-sale due to their long-term purpose. Unrealized gains and losses from securities in these trust funds are reported as adjustments to the regulatory liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the spent nuclear fuel disposal trust funds in accordance with their treatment in rates.

Comprehensive Income (Loss)

Comprehensive income (loss) is defined as the change in equity (net assets) of a business enterprise during a period from transactions and other events and circumstances from non-owner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners. Comprehensive income (loss) has two components: net income (loss) and other comprehensive income (loss).

There were no material differences between net income and comprehensive income for AEGCo.

Components of Accumulated Other Comprehensive Income (Loss)

Accumulated Other Comprehensive Income (Loss) is included on the balance sheet in the equity section. Accumulated Other Comprehensive Income (Loss) for AEP registrant subsidiaries as of December 31, 2003 and 2002 is shown in the following table.

Components	December 31, 2003	2002
	(in thousands)	
Cash Flow Hedges:		
APCo	$(1,569)	$(1,920)
CSPCo	202	(267)
I&M	222	(286)
KPCo	420	322
OPCo	(103)	(738)
PSO	156	(42)
SWEPCo	184	(48)
TCC	(1,828)	(36)
TNC	(601)	(15)
Minimum Pension Liability:		
APCo	$(50,519)	$(70,162)
CSPCo	(46,529)	(59,090)
I&M	(25,328)	(40,201)
KPCo	(6,633)	(9,773)
OPCo	(48,704)	(72,148)
PSO	(43,998)	(54,431)
SWEPCo	(44,094)	(53,635)
TCC	(60,044)	(73,124)
TNC	(26,117)	(30,748)

Earnings Per Share (EPS)

AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC are wholly-owned subsidiaries of AEP and are not required to report EPS.

Supplementary Information

The amounts of power purchased by the registrant subsidiaries from Ohio Valley Electric Corporation, which is 44.2% owned by the AEP System, for the years ended December 31, 2003, 2002 and 2001 were:

	APCo	CSPCo	I&M	OPCo
	(in thousands)			
Year Ended December 31, 2003	$55,219	$15,259	$25,659	$50,995
Year Ended December 31, 2002	53,386	14,885	23,282	50,135
Year Ended December 31, 2001	45,542	12,626	20,723	47,757

Reclassification

Certain prior period financial statement items have been reclassified to conform to current period presentation. Such reclassifications had no impact on previously reported Net Income (Loss).

2. NEW ACCOUNTING PRONOUNCEMENTS, EXTRAORDINARY ITEMS AND CUMULATIVE EFFECT OF ACCOUNTING CHANGES

NEW ACCOUNTING PRONOUNCEMENTS

SFAS 132 (revised 2003) "Employers' Disclosure about Pensions and Other Postretirement Benefits"

In December 2003 the FASB issued SFAS 132 (revised 2003), which requires additional footnote disclosures about pensions and postretirement benefits, some of which are effective beginning with the year-end 2003 financial statements. Other additional disclosures will begin with APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC's 2004 quarterly financial statements.

APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC will implement new quarterly disclosures when they become effective in the first quarter of 2004, including (a) the amount of net periodic benefit cost for each period for which an income statement is presented, showing separately each component thereof, and (b) the amount of employer contributions paid and expected to be paid during the current year, if significantly different from amounts disclosed at the most recent year-end. See Note 11 for these additional 2003 disclosures.

SFAS 142 "Goodwill and Other Intangible Assets"

SFAS 142 requires that goodwill and intangible assets with indefinite useful lives no longer be amortized, and that goodwill and intangible assets be tested annually for impairment. See Note 3 for further information on goodwill and other intangible assets.

SFAS 143 "Accounting for Asset Retirement Obligations"

We implemented SFAS 143, "Accounting for Asset Retirement Obligations," effective January 1, 2003, which requires entities to record a liability at fair value for any legal obligations for asset retirements in the period incurred. Upon establishment of a legal liability, SFAS 143 requires a corresponding asset to be established which will be depreciated over its useful life. SFAS 143 requires that a cumulative effect of change in accounting principle be recognized for the cumulative accretion and accumulated depreciation that would have been recognized had SFAS 143 been applied to existing legal obligations for asset retirements. In addition, the cumulative effect of change in accounting principle is favorably affected by the reversal of accumulated removal cost. These costs had previously been recorded for generation and did not qualify as a legal obligation although these costs were collected in depreciation rates by certain formerly regulated subsidiaries.

We completed a review of our asset retirement obligations and concluded that we have related legal liabilities for nuclear decommissioning costs for I&M's Cook Plant and TCC's partial ownership in the South Texas Project, as well as liabilities for the retirement of certain ash ponds. Since we presently recover our nuclear decommissioning costs in our regulated cash flow and have existing balances recorded for such nuclear retirement obligations, we recognized the cumulative difference between the amount already provided through rates and the amount as measured by applying SFAS 143, as a regulatory asset or liability. Similarly, a regulatory asset was recorded for the cumulative effect of certain retirement costs for ash ponds related to our regulated operations. In 2003, we recorded an unfavorable cumulative effect for the non-regulated operations. See the table later in this section for a summary by registrant subsidiary of the cumulative effect of changes in accounting principles for the year ended December 31, 2003.

Certain of AEP's registrant subsidiaries have collected removal costs from ratepayers for certain assets that do not have associated legal asset retirement obligations. To the extent that such registrant subsidiaries have now been deregulated, the registrant subsidiaries reversed the balance of such removal costs which resulted in a net favorable cumulative effect in 2003. The following is a summary by registrant subsidiary of the removal costs reclassified from Accumulated Depreciation and Amortization to Asset Removal Costs in 2003 and to Deferred Credits and Other in 2002 (Other on AEGCo's 2002 Balance Sheet):

	December 31, 2003	December 31, 2002
	(in millions)	
AEGCo	$ 27.8	$ 28.0
APCo	92.5	94.6
CSPCo	99.1	96.0
I&M	263.0	250.5
KPCo	26.1	23.7
OPCo	101.2	97.0
PSO	214.0	202.6
SWEPCo	236.4	219.5
TCC (a)	104.8	97.5
TNC	76.7	75.0

(a) Includes $9 million classified as Liabilities Held for Sale - Texas Generation Plants on TCC's Consolidated Balance Sheets as of December 31, 2003 and 2002.

The following is a summary by registrant subsidiary of the cumulative effect of change in accounting principle, as a result of SFAS 143, for the year ended December 31, 2003:

	Pre-tax Income (Loss)		After-tax Income (Loss)	
	(in millions)			
	Ash Ponds	Reversal of Cost of Removal	Ash Ponds	Reversal of Cost of Removal
AEGCo	$ -	$ -	$ -	$ -
APCo	(18.2)	146.5	(11.4)	91.7
CSPCo	(7.8)	56.8	(4.7)	33.9
I&M	-	-	-	-
KPCo	-	-	-	-
OPCo	(36.8)	250.4	(21.9)	149.3
PSO	-	-	-	-
SWEPCo	-	13.0	-	8.4
TCC	-	-	-	-
TNC	-	4.7	-	3.1

We have identified, but not recognized, asset retirement obligation liabilities related to electric transmission and distribution as a result of certain easements on property on which we have assets. Generally, such easements are perpetual and require only the retirement and removal of our assets upon the cessation of the property's use. The retirement obligation is not estimable for such easements since we plan to use our facilities indefinitely. The retirement obligation would only be recognized if and when we abandon or cease the use of specific easements.

The following is a reconciliation of beginning and ending aggregate carrying amounts of asset retirement obligations by registrant subsidiary following the adoption of SFAS 143:

	Balance At January 1, 2003	Accretion	Liabilities Incurred	Balance at December 31, 2003
		(in millions)		
AEGCo (a)	$1.1	$-	$-	$1.1
APCo (a)	20.1	1.6	-	21.7
CSPCo (a)	8.1	0.6	-	8.7
I&M (b)	516.1	37.1	-	553.2
OPCo (a)	39.5	3.2	-	42.7
SWEPCo (d)	-	0.3	8.1	8.4
TCC (c)	203.2	15.6	-	218.8

(a) Consists of asset retirement obligations related to ash ponds.
(b) Consists of asset retirement obligations related to ash ponds ($1.1 million at December 31, 2003) and nuclear decommissioning costs for the Cook Plant ($552.1 million at December 31, 2003).
(c) Consists of asset retirement obligations related to nuclear decommissioning costs for STP included in Liabilities Held for Sale – Texas Generation Plants on TCC's Consolidated Balance Sheets.
(d) Consists of asset retirement obligations related to Sabine Mining which is now being consolidated under FIN 46 (see FIN 46 "Consolidation of Variable Interest Entities" later in this note).

Accretion expense is included in Other Operation expense in the respective income statements of the individual subsidiary registrants.

As of December 31, 2003 and 2002, the fair value of assets that are legally restricted for purposes of settling the nuclear decommissioning liabilities totaled $845 million ($720 million for I&M and $125 million for TCC) and $716 million ($618 million for I&M and $98 million for TCC), respectively, recorded in Nuclear Decommissioning and Spent Nuclear Fuel Disposal Trust Funds on I&M's Consolidated Balance Sheets and in Assets Held for Sale-Texas Generation Plants on TCC's Consolidated Balance Sheets.

Pro forma net income has not been presented for the years ended December 31, 2002 and 2001 because the pro forma application of SFAS 143 would result in pro forma net income not materially different from the actual amounts reported for those periods.

The following is a summary by registrant subsidiary of the pro forma liability for asset retirement obligations which has been calculated as if SFAS 143 had been adopted as of the beginning of each period presented:

	December 31,		
	2002	2001	2000
		(in millions)	
AEGCo	$ 1.1	$ 1.0	$0.9
APCo	20.1	18.7	17.3
CSPCo	8.1	7.5	6.9
I&M	516.1	481.4	449.1
KPCo	-	-	-
OPCo	39.5	36.5	33.8
PSO	-	-	-
SWEPCo	-	-	-
TCC	203.2	188.8	175.4
TNC	-	-	-

SFAS 144 "Accounting for the Impairment or Disposal of Long-lived Assets"

In August 2001, the FASB issued SFAS 144, "Accounting for the Impairment or Disposal of Long-lived Assets" which sets forth the accounting to recognize and measure an impairment loss. This standard replaced, SFAS 121, "Accounting for Long-lived Assets and for Long-lived Assets to be Disposed Of." All of the registrant subsidiaries adopted SFAS 144 effective January 1, 2002. See Note 10 for discussion of impairments recognized in 2003 and 2002.

SFAS 145 "Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13, and Technical Corrections"

In April 2002, the FASB issued SFAS 145, "Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13, and Technical Corrections" (SFAS 145). SFAS 145 rescinds SFAS 4, "Reporting Gains and Losses from Extinguishment of Debt," effective for fiscal years beginning after May 15, 2002. SFAS 4 required gains and losses from extinguishment of debt to be aggregated and classified as an extraordinary item if material. In 2003, TCC reclassified Extraordinary Losses (Net of Tax) on its reacquired debt of $2 million for 2001 to Nonoperating Expenses and Nonoperating Income Tax Expense.

SFAS 146 "Accounting for Costs Associated with Exit or Disposal Activities"

In June 2002, FASB issued SFAS 146 which addresses accounting for costs associated with exit or disposal activities. This statement supersedes previous accounting guidance, principally EITF No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)." Under EITF No. 94-3, a liability for an exit cost was recognized at the date of an entity's commitment to an exit plan. SFAS 146 requires that the liability for costs associated with an exit or disposal activity be recognized when the liability is incurred. SFAS 146 also establishes that the liability should initially be measured and recorded at fair value. The time at which we recognize future costs related to exit or disposal activities, including restructuring, as well as the amounts recognized may be affected by SFAS 146. The registrant subsidiaries adopted the provisions of SFAS 146 for exit or disposal activities initiated after December 31, 2002.

SFAS 149 "Amendment of Statement 133 on Derivative Instruments and Hedging Activities"

On April 30, 2003, the FASB issued Statement No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities" (SFAS 149). SFAS 149 amends SFAS 133 to clarify the definition of a derivative and the requirements for contracts to qualify as "normal purchase/normal sale." SFAS 149 also amends certain other existing pronouncements. Effective July 1, 2003, registrant subsidiaries implemented SFAS 149 and the effect was not material to our results of operations, cash flows or financial condition.

SFAS 150 "Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity"

We implemented SFAS 150 effective July 1, 2003. SFAS 150 is the first phase of the FASB's project to eliminate from the balance sheet the "mezzanine" presentation of items with characteristics of both liabilities and equity, including: (1) mandatorily redeemable shares, (2) instruments other than shares that could require the issuer to buy back some of its shares in exchange for cash or other assets and (3) certain obligations that can be settled with shares. Measurement of these liabilities generally is to be at fair value, with the payment or accrual of "dividends" and other amounts to holders reported as interest cost.

Beginning with our third quarter 2003 financial statements, we present Cumulative Preferred Stocks Subject to Mandatory Redemption as Liability for Cumulative Preferred Stock Subject to Mandatory Redemption. Beginning July 1, 2003, we classify dividends on these mandatorily redeemable preferred shares as Interest Charges. In accordance with SFAS 150, dividends from prior periods remain classified as Preferred Stock Dividends.

FIN 45 "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others"

In November 2002, the FASB issued FIN 45 which clarifies the accounting to recognize a liability related to issuing a guarantee, as well as additional disclosures of guarantees. We implemented FIN 45 as of January 1, 2003, and the effect was not material to our results of operations, cash flows or financial condition. See Note 8 for further disclosures.

FIN 46 (revised December 2003)"Consolidation of Variable Interest Entities" and FIN 46 "Consolidation of Variable Interest Entities"

We implemented FIN 46, "Consolidation of Variable Interest Entities," effective July 1, 2003. FIN 46 interprets the application of Accounting Research Bulletin No. 51, "Consolidated Financial Statements," to certain entities in which equity investors do not have the characteristics of a controlling financial interest or do not have sufficient equity at risk for the entity to finance its activities without additional subordinated financial support from other parties. Due to the prospective application of FIN 46, we did not reclassify prior period amounts.

On July 1, 2003, we deconsolidated the trusts which hold mandatorily redeemable trust preferred securities. Therefore, of the $321 million net amount ($75 million PSO, $110 million SWEPCo and $136 million TCC), reported as "Certain Subsidiary Obligated, Mandatorily Redeemable, Preferred Securities of Subsidiary Trusts Holding Solely Junior Subordinated Debentures of Such Subsidiaries" at December 31, 2002, $331 million ($77

million PSO, $113 million SWEPCo and $141 million TCC) is reported as a component of Long-term Debt and $10 million ($2 million PSO, $3 million SWEPCo and $5 million TCC) is reported in Other Investments within Other Property and Investments at December 31, 2003.

Effective July 1, 2003, SWEPCo consolidated Sabine Mining Company (Sabine), a contract mining operation providing mining services to SWEPCo. Upon consolidation, SWEPCo recorded the assets and liabilities of Sabine ($78 million). Also, after consolidation, SWEPCo currently records all expenses (depreciation, interest and other operation expense) of Sabine and eliminates Sabine's revenues against SWEPCo's fuel expenses. There is no cumulative effect of an accounting change recorded as a result of our requirement to consolidate, and there is no change in net income due to the consolidation of Sabine.

Effective July 1, 2003, OPCo consolidated JMG. Upon consolidation, OPCo recorded the assets and liabilities of JMG ($469.6 million). OPCo now records the depreciation, interest and other operating expenses of JMG and eliminates JMG's revenues against OPCo's operating lease expenses. There is no cumulative effect of an accounting change recorded as a result of our requirement to consolidate JMG, and there is no change in net income due to the consolidation of JMG. See Note 15 "Leases" for further disclosures.

In December 2003, the FASB issued FIN 46 (revised December 2003) (FIN 46R) which replaces FIN 46. The FASB and other accounting constituencies continue to interpret the application of FIN 46R. As a result, we are continuing to review the application of this new interpretation and expect to adopt FIN 46R by March 31, 2004.

EITF 02-3 and the Rescission of EITF 98-10

In October 2002, the Emerging Issues Task Force of the FASB reached a final consensus on Issue No. 02-3. EITF 02-3 rescinds EITF 98-10 and related interpretive guidance. Under EITF 02-3, mark-to-market accounting is precluded for risk management contracts that are not derivatives pursuant to SFAS 133. The consensus to rescind EITF 98-10 also eliminated the recognition of physical inventories at fair value other than as provided by GAAP. Registrant subsidiaries have implemented this standard for all physical inventory and non-derivative risk management transactions occurring on or after October 25, 2002. For physical inventory and non-derivative risk management transactions entered into prior to October 25, 2002, registrant subsidiaries implemented this standard on January 1, 2003 and reported the effects of implementation as a cumulative effect of an accounting change (see "Cumulative Effect of Accounting Change" for a summary by registrant subsidiary).

Effective January 1, 2003, EITF 02-3 requires that gains and losses on all derivatives, whether settled financially or physically, be reported in the income statement on a net basis if the derivatives are held for risk management purposes. Previous guidance in EITF 98-10 permitted contracts that were not settled financially to be reported either gross or net in the income statement. Prior to the third quarter of 2002, the registrant subsidiaries recorded and reported upon settlement, sales under forward risk management contracts as revenues. Registrant subsidiaries also recorded and reported purchases under forward risk management contracts as purchased energy expenses. Effective July 1, 2002, the registrant subsidiaries reclassified such forward risk management revenues and purchases on a net basis. The reclassification of such risk management activities to a net basis of reporting resulted in a substantial reduction in both revenues and purchased energy expense, but did not have any impact on financial condition, results of operations or cash flows.

EITF 03-11 "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and Not "Held for Trading Purposes" as Defined in Issue No. 02-3"

In July 2003, the EITF reached consensus on Issue No. 03-11. The consensus states that realized gains and losses on derivative contracts not "held for trading purposes" should be reported either on a net or gross basis based on the relevant facts and circumstances. Reclassification of prior year amounts is not required. The adoption of EITF 03-11 did not have a material impact on our results of operations, financial position or cash flows.

FASB Staff Position No. 106-1, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003

On January 12, 2004, the FASB Staff issued FSP 106-1, which allows a one-time election to defer accounting for

any effects of the prescription drug subsidy under the Medicare Prescription Drug Improvement and Modernization Act of 2003 (the Act), enacted on December 8, 2003. There are significant uncertainties as to whether AEP's plan will be eligible for a subsidy under future federal regulations that have not yet been drafted. The method of accounting for any such subsidy and, therefore, the subsidy's possible reduction to the accumulated postretirement benefit obligation and periodic postretirement benefit costs has not been resolved by the FASB or other professional accounting standard setting authority. Accordingly, any potential effects of the Act were deferred until authoritative guidance on the accounting for the federal subsidy is issued. Measurements of the accumulated postretirement benefit obligation and periodic postretirement benefit cost included in these financial statements do not reflect any potential effects of the Act. APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC cannot determine what impact, if any, new authoritative guidance on the accounting for the federal subsidy may have on our results of operations or financial condition.

Future Accounting Changes

The FASB's standard-setting process is ongoing. Until new standards have been finalized and issued by FASB, we cannot determine the impact on the reporting of our operations that may result from any such future changes.

CUMULATIVE EFFECT OF ACCOUNTING CHANGE

Accounting for Risk Management Contracts

EITF 02-3 rescinds EITF 98-10 and related interpretive guidance. Certain registrant subsidiaries have recorded after tax charges against net income as Accounting for Risk Management Contracts in our Consolidated Statements of Operations in Cumulative Effect of Accounting Changes in the first quarter of 2003. This amount will be realized when the positions settle.

The FASB's Derivative Implementation Group (DIG) issued accounting guidance under SFAS 133 for certain derivative fuel supply contracts with volumetric optionality and derivative electricity capacity contracts. This guidance, effective in the third quarter of 2001, concluded that fuel supply contracts with volumetric optionality cannot qualify for a normal purchase or sale exclusion from mark-to-market accounting and provided guidance for determining when certain option-type contracts and forward contracts in electricity can qualify for the normal purchase or sale exclusion.

Asset Retirement Obligations (SFAS 143)

In the first quarter of 2003, certain of the registrant subsidiaries recorded in after-tax income a cumulative effect of accounting change for Asset Retirement Obligations.

The following is a summary by registrant subsidiary of the cumulative effect of changes in accounting principles recorded in 2003 for the adoptions of SFAS 143 and EITF 02-3 (no effect on AEGCo or PSO):

	SFAS 143 Cumulative Effect		EITF 02-3 Cumulative Effect	
	Pre-tax Income (Loss)	After-tax Income (Loss)	Pre-tax Income (Loss)	After-tax Income (Loss)
	(in millions)		(in millions)	
APCo	$128.3	$ 80.3	$ (4.7)	$ (3.0)
CSPCo	49.0	29.3	(3.1)	(2.0)
I&M	-	-	(4.9)	(3.2)
KPCo	-	-	(1.7)	(1.1)
OPCo	213.6	127.3	(4.2)	(2.7)
SWEPCo	13.0	8.4	0.2	0.1
TCC	-	-	0.2	0.1
TNC	4.7	3.1	-	-

EXTRAORDINARY ITEMS

In 2003 an extraordinary item of $177,000, net of tax of $95,000, was recorded at TNC for the discontinuance of regulatory accounting under SFAS 71 in compliance with a FERC Order dated December 24, 2003 approving a Settlement. AEP's registrant subsidiaries had no extraordinary items in 2002. In 2001 an extraordinary item was recorded for the discontinuance of regulatory accounting under SFAS 71 for the generation portion of the business in the Ohio state jurisdiction. OPCo and CSPCo recognized an extraordinary loss of $48 million (net of tax of $20 million) for unrecoverable Ohio Public Utility Excise Tax (commonly known as the Gross Receipts Tax – GRT) net of allowable Ohio coal credits. This loss resulted from regulatory decisions in connection with Ohio deregulation which stranded the recovery of the GRT. Effective with the liability affixing on May 1, 2001, CSPCo and OPCo recorded an extraordinary loss under SFAS 101. Both Ohio companies appealed to the Ohio Supreme Court the PUCO order on Ohio restructuring that the Ohio companies believe failed to provide for recovery for the final year of the GRT. In April 2002, the Ohio Supreme Court denied recovery of the final year of the GRT.

3. GOODWILL AND OTHER INTANGIBLE ASSETS

Goodwill

There is no goodwill carried by any of the AEP registrant subsidiaries.

Acquired Intangible Assets

SWEPCo's acquired intangible asset subject to amortization is $21.7 million at December 31, 2003 and $24.7 million at December 31, 2002, net of accumulated amortization. The gross carrying amount, accumulated amortization and amortization life are:

		December 31, 2003		December 31, 2002	
	Amortization Life	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
	(in years)	(in millions)		(in millions)	
Advanced royalties	10	$29.4	$7.7	$29.4	$4.7

Amortization of the intangible asset was $3.0 million for the twelve months ended December 31, 2003 and 2002. SWEPCo's estimated aggregate amortization expense is $3 million for each year 2004 through 2010 and $1 million in 2011.

4. RATE MATTERS

In certain jurisdictions, we have agreed to base rate or fuel recovery limitations usually under terms of settlement agreements. See Note 5 for a discussion of those terms related to Nuclear Plant Restart and Merger with CSW.

Fuel in SPP Area of Texas – Affecting SWEPCo and TNC

In 2001, the PUCT delayed the start of customer choice in the SPP area of Texas. In May 2003, the PUCT ordered that competition would not begin in the SPP areas before January 1, 2007. TNC filed with the PUCT in 2002 to determine the most appropriate method to reconcile fuel costs in TNC's SPP area. In April 2003, the PUCT issued an order adopting the methodology proposed in TNC's filing, with adjustments, for reconciling fuel costs in the SPP area. The adjustments removed $3.71 per MWH from reconcilable fuel expense. This adjustment will reduce revenues received by Mutual Energy SWEPCo who now serves TNC's SPP customers by approximately $400,000 annually. In October 2003, Mutual Energy SWEPCo agreed with the PUCT staff and the Office of Public Utility Counsel (OPC) to file a fuel reconciliation proceeding for the period January 2002 through December 2003 by March 31, 2004 and the PUCT ordered that the filing be made.

TNC Fuel Reconciliation – Affecting TNC

In June 2002, TNC filed with the PUCT to reconcile fuel costs, requesting to defer any unrecovered portion applicable to retail sales within its ERCOT service area for inclusion in the 2004 true-up proceeding. This reconciliation for the period of July 2000 through December 2001 will be the final fuel reconciliation for TNC's ERCOT service territory. At December 31, 2001, the deferred under-recovery balance associated with TNC's ERCOT service area was $27.5 million including interest. During the reconciliation period, TNC incurred $293.7 million of eligible fuel costs serving both ERCOT and SPP retail customers. TNC also requested authority to surcharge its SPP customers for under-recovered fuel costs. TNC's SPP customers will continue to be subject to fuel reconciliations until competition begins in the SPP area as described above. The under-recovery balance at December 31, 2001 for TNC's service within SPP was $0.7 million including interest.

In March 2003, the ALJ in this proceeding filed a Proposal for Decision (PFD) with a recommendation that TNC's under-recovered retail fuel balance be reduced. In March 2003, TNC established a reserve of $13 million based on the recommendations in the PFD. In May 2003, the PUCT reversed the ALJ on certain matters and remanded TNC's final fuel reconciliation to the ALJ to consider two issues. The issues are the sharing of off-system sales margins from AEP's trading activities with customers for five years per the PUCT's interpretation of the Texas AEP/CSW merger settlement and the inclusion of January 2002 fuel factor revenues and associated costs in the determination of the under-recovery. The PUCT proposed that the sharing of off-system sales margins for periods beyond the termination of the fuel factor should be recognized in the final fuel reconciliation proceeding. This would result in the sharing of margins for an additional three and one half years after the end of the Texas ERCOT fuel factor.

On December 3, 2003, the ALJ issued a PFD in the remand phase of the TNC fuel reconciliation recommending additional disallowances for the two remand issues. TNC filed responses to the PFD and the PUCT announced a final ruling in the fuel reconciliation proceeding on January 15, 2004 accepting the PFD. TNC is waiting for a written order, after which it will request a rehearing of the PUCT's ruling. While management believes that the Texas merger settlement only provided for sharing of margins during the period fuel and generation costs were regulated by the PUCT, an additional provision of $10 million was recorded in December 2003. Based on the decisions of the PUCT, TNC's final under-recovery including interest at December 31, 2003 was $6.2 million.

In February 2002, TNC received a final order from the PUCT in a previous fuel reconciliation covering the period July 1997 to June 2000 and reflected the order in its financial statements. This final order was appealed to the Travis County District Court. In May 2003, the District Court upheld the PUCT's final order. That order is currently on appeal to the Third Court of Appeals.

TCC Fuel Reconciliation - Affecting TCC

In December 2002, TCC filed its final fuel reconciliation with the PUCT to reconcile fuel costs to be included in its deferred over-recovery balance in the 2004 true-up proceeding. This reconciliation covers the period of July 1998 through December 2001. At December 31, 2001, the over-recovery balance for TCC was $63.5 million including interest. During the reconciliation period, TCC incurred $1.6 billion of eligible fuel and fuel-related expenses.

Based on the PUCT ruling in the TNC proceeding relating to similar issues, TCC established a reserve for potential adverse rulings of $81 million during 2003. In July 2003, the ALJ requested that additional information be provided in the TCC fuel reconciliation related to the impact of the TNC orders, referenced above, on TCC. On February 3, 2004, the ALJ issued a PFD recommending that the PUCT disallow $140 million in eligible fuel costs including some new items not considered in the TNC case, and other items considered but not disallowed in the TNC ruling. At this time, management is unable to predict the outcome of this proceeding. An adverse ruling from the PUCT, disallowing amounts in excess of the established reserve could have a material impact on future results of operations, cash flows and financial condition. Additional information regarding the 2004 true-up proceeding for TCC can be found in Note 6 "Customer Choice and Industry Restructuring."

SWEPCo Texas Fuel Reconciliation – Affecting SWEPCo

In June 2003, SWEPCo filed with the PUCT to reconcile fuel costs in SPP. This reconciliation covers the period of

January 2000 through December 2002. At December 31, 2002, SWEPCo's filing included a $2 million deferred over-recovery balance including interest. During the reconciliation period, SWEPCo incurred $435 million of Texas retail eligible fuel expense. In November 2003, intervenors and the PUCT Staff recommended fuel cost disallowances of more than $30 million. In December 2003, SWEPCo agreed to a settlement in principle with all parties in the fuel reconciliation. The settlement provides for a disallowance in fuel costs of $8 million which was recorded in December 2003. In addition, the settlement provides for the deferral as a regulatory asset of costs of a new lignite mining agreement in excess of a specified benchmark for lignite at SWEPCo's Dolet Hills Plant. The settlement provides for recovery of those deferred costs over a period ending in April 2011 as cost savings are realized under the new mining agreement. The settlement also will allow future recovery of litigation costs associated with the termination of a previous lignite mining agreement if future costs savings are adequate. The settlement will be filed with the PUCT for approval.

ERCOT Price-to-Beat Fuel Factor Appeal – Affecting TCC and TNC

Several parties including the OPC and cities served by both TCC and TNC appealed the PUCT's December 2001 orders establishing initial PTB fuel factors for Mutual Energy CPL and Mutual Energy WTU. On June 25, 2003, the District Court ruled in both appeals. The Court ruled in the Mutual Energy WTU case that the PUCT lacked sufficient evidence to include unaccounted for energy in the fuel factor, and that the PUCT improperly shifted the burden of proof and the record lacked substantial evidence on the effect of loss of load due to retail competition on generation requirements. The Court upheld the initial PTB orders on all other issues. In the Mutual Energy CPL proceeding, the Court ruled that the PUCT improperly shifted the burden of proof and the record lacked substantial evidence on the effect of loss of load due to retail competition on generation requirements. The amount of unaccounted for energy built into the PTB fuel factors was approximately $2.7 million for Mutual Energy WTU. At this time, management is unable to estimate the potential financial impact related to the loss of load issue. The District Court decision was appealed to the Third Court of Appeals by Mutual Energy CPL, Mutual Energy WTU and other parties. Management believes, based on the advice of counsel, that the PUCT's original decision will ultimately be upheld. If the District Court's decisions are ultimately upheld, the PUCT could reduce the PTB fuel factors charged to retail customers in 2002 and 2003 resulting in an adverse effect on future results of operations and cash flows.

Unbundled Cost of Service (UCOS) Appeal – Affecting TCC

The UCOS proceeding established the regulated wires rates to be effective when retail electric competition began. TCC placed new transmission and distribution rates into effect as of January 1, 2002 based upon an order issued by the PUCT resulting from TCC's UCOS proceeding. TCC requested and received approval from the FERC of wholesale transmission rates determined in the UCOS proceeding. Regulated delivery charges include the retail transmission and distribution charge and, among other items, a nuclear decommissioning fund charge, a municipal franchise fee, a system benefit fund fee, a transition charge associated with securitization of regulatory assets and a credit for excess earnings. Certain rulings of the PUCT in the UCOS proceeding, including the initial determination of stranded costs, the requirement to refund TCC's excess earnings, regulatory treatment of nuclear insurance and distribution rates charged municipal customers, were appealed to the Travis County District Court by TCC and other parties to the proceeding. The District Court issued a decision on June 16, 2003, upholding the PUCT's UCOS order with one exception. The Court ruled that the refund of the 1999 through 2001 excess earnings, solely as a credit to non-bypassable transmission and distribution rates charged to REPs, discriminates against residential and small commercial customers and is unlawful. The distribution rate credit began in January 2002. This decision could potentially affect the PTB rates charged by Mutual Energy CPL and could result in a refund to certain of its customers. Mutual Energy CPL was a subsidiary of AEP until December 23, 2002 when it was sold. Management estimates that the effect of a decision to reduce the PTB rates for the period prior to the sale is approximately $11 million pre-tax. The District Court decision was appealed to the Third Court of Appeals by TCC and other parties. Based on advice of counsel, management believes that it will ultimately prevail on appeal. If the District Court's decision is ultimately upheld on appeal or the Court of Appeals reverses the District Court on issues adverse to TCC, it could have an adverse effect on future results of operations and cash flows.

TCC Rate Case – Affecting TCC

On June 26, 2003, the City of McAllen, Texas requested that TCC provide justification showing that its transmission and distribution rates should not be reduced. Other municipalities served by TCC passed similar rate review resolutions. In Texas, municipalities have original jurisdiction over rates of electric utilities within their municipal limits. Under Texas law, TCC must provide support for its rates to the municipalities. TCC filed the requested support for its rates based on a test year ending June 30, 2003 with all of its municipalities and the PUCT on November 3, 2003. TCC's proposal would decrease its wholesale transmission rates by $2 million or 2.5% and increase its retail energy delivery rates by $69 million or 19.2%. On February 9, 2004, eight intervening parties filed testimony recommending reductions to TCC's requested $67 million rate increase. The recommendations range from a decrease in existing rates of approximately $100 million to an increase in TCC's current rates of approximately $27 million. The PUCT Staff filed testimony, on February 17, 2004, recommending reductions to TCC's request of approximately $51 million. TCC's rebuttal testimony was filed on February 26, 2004. Hearings are scheduled for March 2004 with a PUCT decision expected in May 2004. Management is unable to predict the ultimate effect of this proceeding on TCC's rates or its impact on TCC's results of operations, cash flows and financial condition.

Louisiana Fuel Audit – Affecting SWEPCO

The LPSC is performing an audit of SWEPCo's historical fuel costs. In addition, five SWEPCo customers filed a suit in the Caddo Parish District Court in January 2003 and filed a complaint with the LPSC. The customers claim that SWEPCo has over charged them for fuel costs since 1975. The LPSC consolidated the customer complaint and audit. In January 2004, a procedural schedule was issued requiring LPSC Staff and intervenor testimony to be filed in June 2004 and scheduling hearings for October 2004. Management believes that SWEPCo's fuel costs were proper and those costs incurred prior to 1999 have been approved by the LPSC. Management is unable to predict the outcome of these proceedings. If the actions of the LPSC or the Court result in a material disallowance of recovery of SWEPCo's fuel costs from customers, it could have an adverse impact on results of operations and cash flows.

Louisiana Compliance Filing – Affecting SWEPCo

In October 2002, SWEPCo filed with the LPSC detailed financial information typically utilized in a revenue requirement filing, including a jurisdictional cost of service. This filing was required by the LPSC as a result of their order approving the merger between AEP and CSW. The LPSC's merger order also provides that SWEPCo's base rates are capped at the present level through mid 2005. The filing indicates that SWEPCo's current rates should not be reduced. In 2004 the LPSC required SWEPCo to file updated financial information with a test year ending December 31, 2003 before April 16, 2004. If, after review of the updated information, the LPSC disagrees with our conclusion, they could order SWEPCo to file all documents for a full cost of service revenue requirement review in order to determine whether SWEPCo's capped rates should be reduced which would adversely impact results of operations and cash flows.

FERC Wholesale Fuel Complaints – Affecting TNC

Certain TNC wholesale customers filed a complaint with FERC alleging that TNC had overcharged them through the fuel adjustment clause for certain purchased power costs since 1997.

Negotiations to settle the complaint and update the contracts resulted in new contracts. The FERC approved an offer of settlement regarding the fuel complaint and new contracts at market prices in December 2003. Since TNC had recorded a provision for refund in 2002, the effect of the settlement was a $4 million favorable adjustment recorded in December 2003. See Note 2 for a discussion of TNC's discontinuance of SFAS 71 accounting for its FERC jurisdictional customers.

Environmental Surcharge Filing – Affecting KPCo

In September 2002, KPCo filed with the KPSC to revise its environmental surcharge tariff (annual revenue increase of approximately $21 million) to recover the cost of emissions control equipment being installed at the Big Sandy Plant. See NOx Reductions in Note 7.

In March 2003, the KPSC granted approximately $18 million of the request. Annual rate relief of $1.7 million became effective in May 2003 and an additional $16.2 million became effective in July 2003. The recovery of such amounts is intended to offset KPCo's cost of compliance with the Clean Air Act.

PSO Rate Review – Affecting PSO

In February 2003, the Director of the OCC filed an application requiring PSO to file all documents necessary for a general rate review. In October 2003, PSO filed financial information and supporting testimony in response to the OCC's requirements. PSO's response indicates that its annual revenues are $36 million less than costs. As a result, PSO is seeking OCC approval to increase its base rates by that amount, which is a 3.6% increase over PSO's existing revenues. Hearings are scheduled for October 2004. Management is unable to predict the ultimate effect of this review on PSO's rates or its impact on PSO's results of operations, cash flows and financial condition.

PSO Fuel and Purchased Power – Affecting PSO

PSO had a $44 million under-recovery of fuel costs resulting from a 2002 reallocation among AEP West companies of purchased power costs for periods prior to January 1, 2002. In July 2003, PSO filed with the OCC seeking recovery of the $44 million over an 18-month time period. In August 2003, the OCC Staff filed testimony recommending PSO be granted recovery of $42.4 million over three years. In September 2003, the OCC expanded the case to include a full review of PSO's 2001 fuel and purchased power practices. PSO filed its testimony in February 2004 and hearings will occur in June 2004. If the OCC determines as a result of the review that a portion of PSO's fuel and purchased power costs should not be recovered, there will be an adverse effect on PSO's results of operations, cash flows and possibly financial condition.

Merger Mitigation Sales – Affecting PSO, SWEPCo, TCC and TNC

As a condition of AEP/CSW merger approval at the FERC, the AEP West companies were required to mitigate market power concerns in SPP by divesting 300 MW of SPP capacity and selling 300 MW of SPP capacity at auction on an interim basis until the divestiture is completed. The margins from the interim sales were to be shared with customers in accordance with the existing margin sharing if they were positive on an annual basis and customers were to be held harmless if the margins on an annual basis were negative. Consequently, for proper accounting, the margins were deferred until year-end.

On September 1, 2003, AEP sold its share of the Eastex plant located in SPP. As a result of the sale, AEP satisfied the 300 MW FERC divestiture requirement in SPP. Based on the advice of counsel, management has concluded that it is no longer required to make the agreed upon 300 MW interim merger mitigation sale. The AEP West companies had $8.7 million of net merger mitigation sales losses deferred. Since these sales are no longer required, the final adjustment to the accrual occurred in September 2003. The amounts of revenues reversed were $8.6 million by PSO, $0.7 million by TCC and $1.2 million by TNC. SWEPCo recorded its gain of $1.8 million as revenues.

Virginia Fuel Factor Filing – Affecting APCo

APCo filed with the Virginia SCC to reduce its fuel factor effective August 1, 2003. The requested fuel rate reduction was approved by the Virginia SCC and is effective for 17 months (August 1, 2003 to December 31, 2004) and is estimated to reduce revenues by $36 million during that period. This fuel factor adjustment will reduce cash flows without impacting results of operations as any over-recovery or under-recovery of fuel costs would be deferred as a regulatory liability or a regulatory asset.

FERC Long-term Contracts – Affecting AEP East and AEP West companies

In 2002, the FERC set for hearing complaints filed by certain wholesale customers located in Nevada and Washington that sought to break long-term contracts which the customers alleged were "high-priced." At issue were long-term contracts entered into during the California energy price spike in 2000 and 2001. The complaints alleged that AEP sold power at unjust and unreasonable prices.

In February 2003, AEP and one of the customers agreed to terminate their contract. The customer withdrew its FERC complaint and paid $59 million to AEP. As a result of the contract termination, AEP reversed $69 million of unrealized mark-to-market gains previously recorded, resulting in a $10 million pre-tax loss.

In December 2002, a FERC ALJ ruled in favor of AEP and dismissed a complaint filed by two Nevada utilities. In 2000 and 2001, we agreed to sell power to the utilities for future delivery. In 2001, the utilities filed complaints asserting that the prices for power supplied under those contracts should be lowered because the market for power was allegedly dysfunctional at the time such contracts were executed. The ALJ rejected the utilities' complaint, held that the markets for future delivery were not dysfunctional, and that the utilities had failed to demonstrate that the public interest required that changes be made to the contracts. In June 2003, the FERC issued an order affirming the ALJ's decision. The utilities requested a rehearing which the FERC denied. The utilities' appeal of the FERC order is pending before the U.S. Court of Appeals for the Ninth Circuit. Management is unable to predict the outcome of this proceeding and its impact on future results of operations and cash flows.

RTO Formation/Integration Costs – Affecting APCo, CSPCo, I&M, KPCo, and OPCo

With FERC approval, AEP East companies have been deferring costs incurred under FERC orders to form an RTO (the Alliance RTO) or join an existing RTO (PJM). In July 2003, the FERC issued an order approving our continued deferral of both our Alliance formation costs and our PJM integration costs including the deferral of a carrying charge. The AEP East companies have deferred approximately $28 million of RTO formation and integration costs and related carrying charges through December 31, 2003. Amounts per company are as follows:

Company	(in millions)
APCo	$7.8
CSPCo	3.3
I&M	6.0
KPCo	1.8
OPCo	8.6

As a result of the subsequent delay in the integration of AEP's East transmission system into PJM, FERC declined to rule, in its July 2003 order, on our request to transfer the deferrals to regulatory assets, and to maintain the deferrals until such time as the costs can be recovered from all users of AEP's East transmission system. The AEP East companies will apply for permission to transfer the deferred formation/integration costs to a regulatory asset prior to integration with PJM. In August 2003, the Virginia SCC filed a request for rehearing of the July 2003 order, arguing that FERC's action was an infringement on state jurisdiction, and that FERC should not have treated Alliance RTO startup costs in the same manner as PJM integration costs. On October 22, 2003, FERC denied the rehearing request.

In its July 2003 order, FERC indicated that it would review the deferred costs at the time they are transferred to a regulatory asset account and scheduled for amortization and recovery in the open access transmission tariff (OATT) to be charged by PJM. Management believes that the FERC will grant permission for the deferred RTO costs to be amortized and included in the OATT. Whether the amortized costs will be fully recoverable depends upon the state regulatory commissions' treatment of AEP East companies' portion of the OATT at the time they join PJM. Presently, retail base rates are frozen or capped and cannot be increased for retail customers of CSPCo, I&M and OPCo. APCo's Virginia retail base rates are capped with an opportunity for a one-time increase in non-generation rates after January 1, 2004. We intend to file an application with FERC seeking permission to delay the amortization of the deferred RTO formation/integration costs until they are recoverable from all users of the transmission system including retail customers. Management is unable to predict the timing of when AEP will join PJM and if upon joining PJM whether FERC will grant a delay of recovery until the rate caps and freezes end. If

the AEP East companies do not obtain regulatory approval to join PJM, we are committed to reimburse PJM for certain project implementation costs (presently estimated at $24 million for the entire PJM integration project). If incurred, PJM project implementation costs will be allocated among the AEP East companies. Management intends to seek recovery of the deferred RTO formation/integration costs and project implementation cost reimbursements, if incurred. If the FERC ultimately decides not to approve a delay or the state commissions deny recovery, future results of operations and cash flows could be adversely affected.

In the first quarter of 2003, the state of Virginia enacted legislation preventing APCo from joining an RTO prior to July 1, 2004 and thereafter only with the approval of the Virginia SCC, but required such transfers by January 1, 2005. In January 2004, APCo filed with the Virginia SCC a cost/benefit study covering the time period through 2014 as required by the Virginia SCC. The study results show a net benefit of approximately $98 million for APCo over the 11-year study period from AEP's participation in PJM.

In July 2003, the KPSC denied KPCo's request to join PJM based in part on a lack of evidence that it would benefit Kentucky retail customers. In August 2003, KPCo sought and was granted a rehearing to submit additional evidence. In December 2003, AEP filed with the KPSC a cost/benefit study showing a net benefit of approximately $13 million for KPCo over the five-year study period from AEP's participation in PJM. A hearing has been scheduled in April 2004.

In September 2003, the IURC issued an order approving I&M's transfer of functional control over its transmission facilities to PJM, subject to certain conditions included in the order. The IURC's order stated that AEP shall request and the IURC shall complete a review of Alliance formation costs before any deferral of the costs for future recovery.

In November 2003, the FERC issued an order preliminarily finding that AEP must fulfill its CSW merger condition to join an RTO by integrating into PJM (transmission and markets) by October 1, 2004. The order was based on PURPA 205(a), which allows FERC to exempt electric utilities from state law or regulation in certain circumstances. The FERC set several issues for public hearing before an ALJ. Those issues include whether the laws, rules, or regulations of Virginia and Kentucky are preventing AEP from joining an RTO and whether the exceptions under PURPA apply. The FERC directed the ALJ to issue an initial decision by March 15, 2004.

FERC Order on Regional Through and Out Rates – Affecting APCo, CSPCo, I&M, KPCo and OPCo

In July 2003, the FERC issued an order directing PJM and the Midwest ISO to make compliance filings for their respective Open Access Transmission Tariffs to eliminate, by November 1, 2003, the transaction-based charges for through and out (T&O) transmission service on transactions where the energy is delivered within the proposed Midwest ISO and PJM expanded regions (RTO Footprint). In October 2003, the FERC postponed the November 1, 2003 deadline to eliminate T&O rates. The elimination of the T&O rates will reduce the transmission service revenues collected by the RTOs and thereby reduce the revenues received by transmission owners under the RTOs' revenue distribution protocols. The order provided that affected transmission owners could file to offset the elimination of these revenues by increasing rates or utilizing a transitional rate mechanism to recover lost revenues that result from the elimination of the T&O rates. The FERC also found that the T&O rates of some of the former Alliance RTO companies, including AEP, may be unjust, unreasonable, and unduly discriminatory or preferential for energy delivered in the RTO Footprint. FERC initiated an investigation and hearing in regard to these rates. We made a filing with the FERC to support the justness and reasonableness of our rates. We also made a joint filing with unaffiliated utilities proposing a regional revenue replacement mechanism for the lost revenues, in the event that FERC eliminated all T&O rates for delivery points within the RTO Footprint. In orders issued in November 2003, the FERC dismissed the joint filing, but adopted a new regional rate design substantially in the form proposed in the joint filing. The orders, directed each transmission provider to file compliance rates to eliminate T&O rates prospectively within the region and simultaneously implement a new seams elimination cost allocation (SECA) rates to mitigate the lost revenues for a two-year transition period beginning April 1, 2004. The FERC did not indicate the recovery method for the revenues after the two-year period. As required by the FERC, we filed compliance tariff changes in January 2004 to eliminate the T&O charges within the RTO Footprint. The SECA rate issues that remain unresolved have been set before an ALJ for settlement procedures, and the effective date of the T&O rate elimination and SECA rates were delayed until May 1, 2004. The November 2003 orders have been appealed by a number of parties. The AEP East companies received approximately $150 million of T&O rate revenues from transactions delivering energy to customers in the RTO Footprint for the twelve months

ended June 30, 2003. At this time, management is unable to predict whether the new SECA rates will fully compensate the AEP East companies for their lost T&O rate revenues and, consequently, their impact on our future results of operations, cash flows and financial condition.

Indiana Fuel Order – Affecting I&M

On July 17, 2003, I&M filed a fuel adjustment clause application requesting authorization to implement the fixed fuel adjustment charge (fixed pursuant to a prior settlement of the Cook Nuclear Plant Outage) for electric service for the billing months of October 2003 through February 2004, and for approval of a new fuel cost adjustment credit for electric service to be applicable during the March 2004 billing month.

On August 27, 2003, the IURC issued an order approving the requested fixed fuel adjustment charge for October 2003 through February 2004. The order further stated that certain parties must negotiate the appropriate action on fuel to commence on March 1, 2004. Such negotiations are ongoing. The IURC deferred ruling on the March 2004 factor until after January 1, 2004.

Michigan 2004 Fuel Recovery Plan – Affecting I&M

The MPSC's December 16, 1999 order approved a Settlement Agreement regarding the extended outage of the Cook Plant and fixed I&M Power Supply Cost Recovery (PSCR) factors for the St. Joseph and Three Rivers rate areas through December 2003. In accordance with the settlement, PSCR Plan cases were not required to be filed through the 2003 plan year. As required, I&M filed its 2004 PSCR Plan with the MPSC on September 30, 2003 seeking new fuel and power supply recovery factors to be effective in 2004. The case has been scheduled for hearing. As allowed by Michigan law, the proposed factors were effective on January 1, 2004, subject to review and possible adjustment based on the results of the hearing.

5. EFFECTS OF REGULATION

Regulatory Assets and Liabilities

Regulatory assets and liabilities are comprised of the following items:

	AEGCo			APCo		
	2003	2002	Recovery/Refund Period	2003	2002	Recovery/Refund Period
			(in thousands)			
Regulatory Assets:						
SFAS 109 Regulatory Asset, Net				$325,889	$209,884	Various Periods (a)
Transition Regulatory Assets – Virginia				30,855	39,670	Up to 4 Years (a)
Transition Regulatory Assets – West Virginia				-	119,038	N/A
Deferred Fuel Costs				-	5,367	N/A
Unamortized Loss on Reacquired Debt	$4,733	$4,970	22 Years (b)	19,005	9,147	Up to 29 Years (b)
Asset Retirement Obligations	928	-	Various Periods (a)	9,048	-	Various Periods (a)
Unrealized Loss on Forward Commitments				17,006	-	Various Periods (a)
Other				15,393	12,447	Various Periods (a)
Total Regulatory Assets	$5,661	$4,970		$417,196	$395,553	
Regulatory Liabilities:						
Asset Removal Costs	$27,822	$-	(d)	$92,497	$-	(d)
Deferred Investment Tax Credits	49,589	52,943	Up to 19 Years (a)	30,545	33,691	Up to 17 Years (c)
WV Rate Stabilization Deferral				-	75,601	N/A
SFAS 109 Regulatory Liability, Net	15,505	16,670	Various Periods (a)			
Over Recovery of Fuel Costs – West Virginia				55,250	-	(a)
Unrealized Gain on Forward Commitments				17,283	-	Various Periods (a)
Over Recovery of Fuel Costs – Virginia				13,454	-	1 Year (b)
Other				43	72	Various Periods (a)
Total Regulatory Liabilities	$92,916	$69,613		$209,072	$109,364	

(a) Amount does not earn a return.
(b) Amount effectively earns a return.
(c) A portion of this amount effectively earns a return.
(d) The liability for removal costs will be discharged as removal costs are incurred over the life of the plant.

	CSPCo			I&M		
			Recovery/Refund			Recovery/Refund
	2003	2002	Period	2003	2002	Period
			(in thousands)			
Regulatory Assets:						
SFAS 109 Regulatory Asset, Net	$16,027	$26,290	Various Periods (a)	$151,973	$163,928	Various Periods (a)
Transition Regulatory Assets	188,532	204,961	Up to 5 Years (a)			
Deferred Fuel Costs				-	37,501	N/A
Unamortized Loss on Reacquired Debt	13,659	5,978	Up to 20 Years (b)	18,424	14,994	Up to 29 Years (b)
Cook Plant Restart Costs				-	40,000	N/A
Incremental Nuclear Refueling Outage Expenses, Net				57,326	29,572	(c)
DOE Decontamination and Decommissioning Assessment				18,863	23,375	Up to 5 Years (a)
Other	24,966	20,453	Various Periods (a)	29,691	38,842	Various Periods (a)
Total Regulatory Assets	$243,184	$257,682		$276,277	$348,212	
Regulatory Liabilities:						
Asset Removal Costs	$99,119	$-	(e)	$263,015	$-	(e)
Deferred Investment Tax Credits	30,797	33,907	Up to 17 Years (a)	90,278	97,709	Up to 19 Years (a)
Excess ARO for Nuclear Decommissioning				215,715	-	(d)
Unrealized Gain on Forward Commitments				25,010	36,804	Various Periods (a)
Other				36,258	29,179	Various Periods (a)
Total Regulatory Liabilities	$129,916	$33,907		$630,276	$163,692	

(a) Amount does not earn a return.
(b) Amount effectively earns a return.
(c) Amortized over the period beginning with the commencement of an outage and ending with the beginning of the next outage and does not earn a return.
(d) This is the cumulative difference in the amount provided through rates and the amount as measured by applying SFAS 143. Accrues monthly, will be paid when the nuclear plant is decommissioned and earns a return.
(e) The liability for removal costs will be discharged as removal costs are incurred over the life of the plant.

	KPCo			OPCo		
			Recovery/Refund			Recovery/Refund
	2003	2002	Period	2003	2002	Period
			(in thousands)			
Regulatory Assets:						
SFAS 109 Regulatory Asset, Net	$99,828	$87,261	Various Periods (a)	$169,605	$165,106	Various Periods (a)
Transition Regulatory Assets				310,035	375,409	4 years (a)
Unamortized Loss on Reacquired Debt	1,088	152	Up to 29 Years (b)	10,172	4,899	Up to 34 Years (b)
Other	12,883	14,563	Various Periods (a)	22,506	23,227	Various Periods (a)
Total Regulatory Assets	$113,799	$101,976		$512,318	$568,641	
Regulatory Liabilities:						
Asset Removal Costs	$26,140	$-	(c)	$101,160	$-	(c)
Deferred Investment Tax Credits	7,955	9,165	Up to 17 Years (a)	15,641	18,748	Up to 17 Years (a)
Unrealized Gain on Forward Commitments	9,174	10,967	Various Periods (a)			
Other	1,417	1,185	Various Periods (a)	3	1,237	Various Periods (a)
Total Regulatory Liabilities	$44,686	$21,317		$116,804	$19,985	

(a) Amount does not earn a return.
(b) Amount effectively earns a return.
(c) The liability for removal costs will be discharged as removal costs are incurred over the life of the plant.

	PSO			SWEPCo		
			Recovery/Refund			Recovery/Refund
	2003	2002	Period	2003	2002	Period
			(in thousands)			
Regulatory Assets:						
SFAS 109 Regulatory Asset, Net				$3,235	$19,855	Various Periods (b)
Under-recovered Fuel Costs	$24,170	$76,470	1 Year (a)	11,394	2,865	1 Year (a)
Unamortized Loss on Reacquired Debt	14,357	11,138	Up to 12 Years (b)	19,331	17,031	Up to 40 Years (b)
Other	14,342	15,012	Various Periods (c)	15,859	12,347	Various Periods (c)
Total Regulatory Assets	$52,869	$102,620		$49,819	$52,098	
Regulatory Liabilities:						
Asset Removal Costs	$214,033	$-	(e)	$236,409	$-	(e)
Deferred Investment Tax Credits	30,411	32,201	Up to 26 Years (d)	39,864	44,190	Up to 14 Years (d)
SFAS 109 Regulatory Liability, Net	24,937	27,893	Various Periods (b)			
Over-Recovered Fuel Costs				4,178	17,226	1 Year (a)
Excess Earnings				2,600	3,700	(d)
Unrealized Gains on Forward Commitments	15,406	4,360	Various Periods (c)	11,793	1,992	Various Periods (c)
Other	-	31	Various Periods (c)	6,986	1,402	Various Periods (c)
Total Regulatory Liabilities	$284,787	$64,485		$301,830	$68,510	

(a) Deferred fuel for PSO's Oklahoma jurisdiction & SWEPCo's Arkansas and Louisiana jurisdictions does not earn a return. Texas jurisdictional amounts do earn a return.
(b) Amount effectively earns a return.
(c) Amounts are both earning and not earning a return.
(d) Amount does not earn a return.
(e) The liability for removal costs will be discharged as removal costs are incurred over the life of the plant.

	TCC			TNC		
	2003	2002	Recovery/Refund Period	2003	2002	Recovery/Refund Period
			(in thousands)			
Regulatory Assets:						
SFAS 109 Regulatory Asset, Net	$3,249	$9,950	Various Periods (a)			
Designated For Securitization	1,253,289	330,960	(b)			
Deferred Fuel Costs				$26,680	$26,680	(c)
Wholesale Capacity Auction True-up	480,000	262,000	(c)			
Unamortized Loss on Reacquired Debt	9,086	8,661	Up to 34 Years (a)	3,929	3,283	Up to 17 Years (a)
Deferred Debt – Restructuring	12,015	13,324	Up to 14 Years (a)	6,579	10,134	Up to 14 Years (a)
DOE Decontamination and Decommissioning Assessment	3,268	3,170	1 Year (d)			
Other	130,645	166,931	Various Periods (e)	3,332	5,000	Various Periods (e)
Total Regulatory Assets	$1,891,552	$794,996		$40,520	$45,097	
Regulatory Liabilities:						
Asset Removal Costs	$95,415	$-	(f)	$76,740	$-	(f)
Deferred Investment Tax Credits	112,479	117,686	Up to 25 Years (d)	19,990	21,510	Up to 19 Years (d)
Deferred Fuel Costs	69,026	69,026	(c)			
Retail Clawback	45,527	51,926	(c)	11,804	14,328	(c)
Over – Recovery of Transition Charges	22,499	20,870	Up to 13 Years (a)			
Purchased Power Conservation	9,234	9,560	Various Periods (e)			
Excess Earnings	25,246	46,111	(b)	14,262	17,419	Up to 30 Years (a)
SFAS 109 Regulatory Liability, Net				13,655	12,280	Various Periods (a)
Other	5	6	Various Periods (e)	1,826	7,285	Various Periods (e)
Total Regulatory Liabilities	$379,431	$315,185		$138,277	$72,822	

(a) Amount earns a return.
(b) Will be included in TCC's PUCT 2004 true-up proceedings and is designated for possible securitization during 2005.
(c) Amount will be included in TCC's and TNC's 2004 true-up proceedings for future recovery/payment over a time period to be determined in a future PUCT proceeding.
(d) Amount does not earn a return.
(e) Amounts are both earning and not earning a return.
(f) The liability for removal costs will be discharged as removal costs are incurred over the life of the plant.

Texas Restructuring Related Regulatory Assets and Liabilities

Regulatory assets Designated for Securitization, Wholesale Capacity Auction True-up regulatory assets, Deferred Fuel Costs and Retail Clawback regulatory liabilities are not being currently recovered from or returned to ratepayers. Management believes that the laws and regulations, established in Texas for industry restructuring, provide for the recovery from ratepayers of these net amounts. See Note 6 for a complete discussion of our plans to recover these regulatory assets, net of regulatory liabilities.

Nuclear Plant Restart

I&M completed the restart of both units of the Cook Plant in 2000. Settlement agreements in the Indiana and Michigan retail jurisdictions that addressed recovery of Cook Plant related outage costs were approved in 1999 by the IURC and MPSC.

The amount of deferrals amortized to other O&M expenses were $40 million in 2003, 2002 and 2001. Also pursuant to the settlement agreements, accrued fuel-related revenues of approximately $37 million in 2003 and $38 million in 2002 and 2001 were amortized as a reduction of revenues.

The amortization of O&M costs and fuel-related revenues deferred under Indiana and Michigan retail jurisdictional settlement agreements adversely affected results of operations through December 31, 2003 when the amortization period ended.

Merger with CSW

On June 15, 2000, AEP merged with CSW so that CSW became a wholly-owned subsidiary of AEP. In connection with the merger, non-recoverable merger costs were expensed in 2003, 2002 and 2001. Such costs included transaction and transition costs not recoverable from ratepayers. Also included in the merger costs were non-recoverable change in control payments. Merger transaction and transition costs recoverable from ratepayers were deferred pursuant to state regulator approved settlement agreements through December 31, 2003. The deferred merger costs are being amortized over five to eight year recovery periods, depending on the specific terms of the settlement agreements, with the amortization included in depreciation and amortization expense.

The following tables show the deferred merger cost and amortization expense of the applicable subsidiary registrants:

	Merger Cost Deferral December 31, 2003	Amortization Expense for the Year Ended December 31, 2003
	(in millions)	
I&M	$6.7	$1.7
KPCo	2.4	0.6
PSO	3.2	1.9
SWEPCo	2.7	1.2
TCC	6.5	2.6
TNC	1.9	0.8

	Merger Cost Deferral December 31, 2002	Amortization Expense for the Year Ended December 31, 2002
	(in millions)	
I&M	$8.2	$1.7
KPCo	2.9	0.6
PSO	5.0	1.6
SWEPCo	3.9	1.1
TCC	9.1	2.6
TNC	2.7	0.8

	Merger Cost Deferral December 31, 2001	Amortization Expense for the Year Ended December 31, 2001
	(in millions)	
I&M	$9.1	$1.7
KPCo	3.2	0.6
PSO	6.6	1.2
SWEPCo	5.0	1.1
TCC	11.8	2.6
TNC	3.5	0.8

Merger transition costs are expected to continue to be incurred for several years after the merger and will be expensed or deferred for amortization as appropriate. As hereinafter summarized, the state settlement agreements provide for, among other things, a sharing of net merger savings with certain regulated customers over periods of up to eight years through rate reductions which began in the third quarter of 2000.

Summary of key provisions of Merger Rate Agreements:

State/Company	Ratemaking Provisions
Texas – SWEPCo, TCC, TNC	$221 million rate reduction over 6 years. No base rate increases for 3 years post merger.
Indiana – I&M	$67 million rate reduction over 8 years. Extension of base rate freeze until January 1, 2005. Requires additional annual deposits of $6 million to the nuclear decommissioning trust fund for the years 2001 through 2003.
Michigan – I&M	Customer billing credits of approximately $14 million over 8 years. Extension of base rate freeze until January 1, 2005.
Kentucky – KPCo	Rate reductions of approximately $28 million over 8 years. No base rate increases for 3 years post merger.
Oklahoma – PSO	Rate reductions of approximately $28 million over 5 years. No base rate increase before January 1, 2003.
Arkansas – SWEPCo	Rate reductions of $6 million over 5 years. No base rate increase before June 15, 2003.
Louisiana – SWEPCo	Rate reductions to share merger savings estimated to be $18 million over 8 years. Base rate cap until June 2005.

If actual merger savings are significantly less than the merger savings rate reductions required by the merger settlement agreements in the eight-year period following consummation of the merger, future results of operations, cash flows and possibly financial condition could be adversely affected.

See Note 7, "Commitments and Contingencies" for information on a court decision concerning the merger.

6. CUSTOMER CHOICE AND INDUSTRY RESTRUCTURING

Prior to 2003, retail customer choice began in four of the eleven state retail jurisdictions (Michigan, Ohio, Texas and Virginia) in which the AEP domestic electric utility companies operate. The following paragraphs discuss significant events occurring related to customer choice and industry restructuring.

OHIO RESTRUCTURING – Affecting CSPCo and OPCo

On June 27, 2002, the Ohio Consumers' Counsel, Industrial Energy Users–Ohio and American Municipal Power–Ohio filed a complaint with the PUCO alleging that CSPCo and OPCo have violated the PUCO's orders regarding implementation of their transition plan and violated the applicable law by failing to participate in an RTO.

The complainants seek, among other relief, an order from the PUCO:

- suspending collection of transition charges by CSPCo and OPCo until transfer of control of their transmission assets has occurred
- requiring the pricing of standard offer electric generation effective January 1, 2006 at the market price used by CSPCo and OPCo in their 1999 transition plan filings to estimate transition costs and
- imposing a $25,000 per company forfeiture for each day AEP fails to comply with its commitment to transfer control of transmission assets to an RTO

Due to FERC, state legislative and regulatory developments, CSPCo and OPCo have been delayed in the implementation of their RTO participation plans. We continue to pursue integration of CSPCo, OPCo and other AEP East companies into PJM. In this regard, on December 19, 2002, CSPCo and OPCo filed an application with the PUCO for approval of the transfer of functional control over certain of their transmission facilities to PJM. In February 2003, the PUCO consolidated the June 2002 complaint with our December application. CSPCo's and OPCo's motion to dismiss the complaint has been denied by the PUCO and the PUCO affirmed that ruling in rehearing. All further action in the consolidated case has been stayed "until more clarity is achieved regarding matters pending at the FERC and elsewhere." Management is currently unable to predict the timing of the AEP East companies' (including CSPCo and OPCo) participation in PJM, the outcome of these proceedings before the PUCO or their impact on results of operations and cash flows.

In October 2002, the PUCO initiated an investigation of the financial condition of Ohio's regulated public utilities. The PUCO's goal is to identify measures available to the PUCO to ensure that the regulated operations of Ohio's public utilities are not impacted by adverse financial consequences of parent or affiliate company unregulated operations and take appropriate corrective action, if necessary. The utilities and other interested parties were requested to provide comments and suggestions by November 12, 2002, with reply comments by November 22, 2002, on the type of information necessary to accomplish the stated goals, the means to gather the required information from the public utilities and potential courses of action that the PUCO could take. In January 2004, the PUCO staff issued a report recommending that the PUCO seek more authority from the Ohio Legislature on this issue. The PUCO has taken no further action in this proceeding. Management is unable to predict the outcome of the PUCO's investigation or its impact on results of operations, cash flows and business practices, if any.

On March 20, 2003, the PUCO commenced a statutorily required investigation concerning the desirability, feasibility and timing of declaring retail ancillary, metering or billing and collection service, supplied to customers within the certified territories of electric utilities, a competitive retail electric service. The PUCO sent out a list of questions and set June 6, 2003 and July 7, 2003 as the dates for initial responses and replies, respectively. CSPCo and OPCo filed comments and responses in compliance with the PUCO's schedule. Management is unable to predict the timing or the outcome of this proceeding or its impact on results of operations or cash flows.

The Ohio Act provides for a Market Development Period (MDP) during which retail customers can choose their electric power suppliers or receive Default Service at frozen generation rates from the incumbent utility. The MDP began on January 1, 2001 and is scheduled to terminate no later than December 31, 2005. The PUCO may terminate the MDP for one or more customer classes before that date if it determines either that effective competition exists in the incumbent utility's certified territory or that there is a twenty percent switching rate of the incumbent utility's load by customer class. Following the MDP, retail customers will receive distribution and transmission service from the incumbent utility whose distribution rates will be approved by the PUCO and whose transmission rates will be approved by the FERC. Retail customers will continue to have the right to choose their electric power suppliers or receive Default Service, which must be offered by the incumbent utility at market rates. On December 17, 2003, the PUCO adopted a set of rules concerning the method by which it will determine market rates for Default Service following the MDP. The rule provides for a Market Based Standard Service Offer which would be a variable rate based on a transparent forward market, daily market, and/or hourly market prices. The

rule also requires a fixed-rate Competitive Bidding Process for residential and small nonresidential customers and permits a fixed-rate Competitive Bidding Process for large general service customers and other customer classes. Customers who do not switch to a competitive generation provider can choose between the Market Based Standard Service Offer or the Competitive Bidding Process. Customers who make no choice will be served pursuant to the Competitive Bidding Process.

On February 9, 2004, CSPCo and OPCo filed their rate stabilization plan with the PUCO addressing rates following the end of the MDP, which ends December 31, 2005. If approved by the PUCO, rates would be established pursuant to the plan for the period from January 1, 2006 through December 31, 2008 instead of the rates discussed in the previous paragraph. The plan is intended to provide rate stability and certainty for customers, facilitate the development of a competitive retail market in Ohio, provide recovery of environmental and other costs during the plan period and improve the environmental performance of AEP's generation resources that serve Ohio customers. The plan includes annual, fixed increases in the generation component of all customers' bills (3% annually for CSPCo and 7% annually for OPCo), and the opportunity for additional generation-related increases upon PUCO review and approval. For residential customers, however, if the temporary 5% generation rate discount provided by the Ohio Act were eliminated on June 30, 2004, the fixed increases would be 1.6% for CSPCo and 5.7% for OPCo. The generation-related increases under the plan would be subject to caps. The plan would maintain distribution rates through the end of 2008 for CSPCo and OPCo at the level effective on December 31, 2005. Such rates could be adjusted for specified reasons through a PUCO filing. Transmission charges can be adjusted to reflect applicable charges approved by the FERC related to open access transmission, net congestion, and ancillary services. The plan also provides for continued recovery of transition regulatory assets and deferral of regulatory assets in 2004 and 2005 for RTO costs and carrying costs on required environmental expenditures. A procedural schedule has not been established for this filing. Management cannot predict whether the plan will be approved as submitted, modified by the PUCO, or its impacts on results of operation and cash flows.

As provided in stipulation agreements approved by the PUCO in 2000, CSPCo and OPCo are deferring customer choice implementation costs and related carrying costs that are in excess of $20 million per company. The agreements provide for the deferral of these costs as a regulatory asset until the company's next distribution base rate case. The February 2004 filing provides for the continued deferrals of customer choice implementation costs during the rate stabilization plan period. At December 31, 2003, CSPCo has incurred $32 million and deferred $12 million and OPCo has incurred $34 million and deferred $14 million of such costs. Recovery of these regulatory assets will be subject to PUCO review in each company's future Ohio filings for new distribution rates. If the rate stabilization plan is approved, it would defer recovery of these amounts until after the end of the rate stabilization period. Management believes that the customer choice implementation costs were prudently incurred and the deferred amounts should be recoverable in future rates. If the PUCO determines that any of the deferred costs are unrecoverable, it would have an adverse impact on future results of operations and cash flows.

TEXAS RESTRUCTURING – Affecting SWEPCo, TCC and TNC

Texas Legislation enacted in 1999 provided the framework and timetable to allow retail electricity competition for all customers. On January 1, 2002, customer choice of electricity supplier began in the ERCOT area of Texas. Customer choice has been delayed in the SPP area of Texas until at least January 1, 2007.

The Texas Legislation, among other things:

- provides for the recovery of regulatory assets and other stranded costs through securitization and non-bypassable wires charges;
- requires each utility to structurally unbundle into a retail electric provider, a power generation company and a transmission and distribution (T&D) utility;
- provides for an earnings test for each of the years 1999 through 2001 and;
- provides for a 2004 true-up proceeding. See 2004 true-up proceeding discussion below.

The Texas Legislation required vertically integrated utilities to legally separate their generation and retail-related assets from their transmission and distribution-related assets. Prior to 2002, TCC and TNC functionally separated their operations to comply with the Texas Legislation requirements. AEP formed new subsidiaries to act as

affiliated REPs for TCC and TNC effective January 1, 2002 (the start date of retail competition). In December 2002, AEP sold the affiliated REPs to an unaffiliated company.

In 1999, TCC filed with the PUCT to securitize $1.27 billion of its retail generation-related regulatory assets and $47 million in other qualified restructuring costs. The PUCT authorized the issuance of up to $797 million of securitization bonds ($949 million of generation-related regulatory assets and $33 million of qualified refinancing costs offset by $185 million of customer benefits for accumulated deferred income taxes). TCC issued its securitization bonds in February 2002. The amount not approved for securitization will be included in regulatory assets/stranded costs in TCC's 2004 true-up proceeding.

TEXAS 2004 TRUE-UP PROCEEDING

A 2004 true-up proceeding will determine the amount and recovery of:

- net stranded generating plant costs and generation-related regulatory assets (stranded costs),
- a true-up of actual market prices determined through legislatively-mandated capacity auctions to the power costs used in the PUCT's ECOM model for 2002 and 2003 (wholesale capacity auction true-up),
- final approved deferred fuel balance,
- unrefunded accumulated excess earnings,
- excess of price-to-beat revenues over market prices subject to certain conditions and limitations (retail clawback) and
- other restructuring true-up items

The PUCT adopted a rule in 2003 regarding the timing of the 2004 true-up proceedings scheduling TNC's filing in May 2004 and TCC's filing in September 2004 or 60 days after the completion of the sale of TCC's generation assets, if later.

Stranded Costs and Generation-Related Regulatory Assets

Restructuring legislation required utilities with stranded costs to use market-based methods to value certain generating assets for determining stranded costs. TCC is the only AEP subsidiary that has stranded costs under the Texas Legislation. We have elected to use the sale of assets method to determine the market value of all of our generation assets for stranded cost purposes. When completed, the sale of our generation assets will substantially complete the required separation of generation assets from transmission and distribution assets. For purposes of the 2004 true-up proceeding, the amount of stranded costs under this market valuation methodology will be the amount by which the book value of TCC's generating assets, including regulatory assets and liabilities that were not securitized, exceeds the market value of the generation assets as measured by the net proceeds from the sale of the assets. It is anticipated that any such sale will result in significant stranded costs for purposes of TCC's 2004 true-up proceeding.

In December 2002, TCC filed a plan of divestiture with the PUCT seeking approval of a sales process for all of its generating facilities. In March 2003, the PUCT dismissed TCC's divestiture filing, determining that it was more appropriate to address allowable valuation methods for the nuclear asset in a rulemaking proceeding. The PUCT approved a rule, in May 2003, which allows the market value obtained by selling nuclear assets to be used in determining stranded costs. Although the PUCT declined to review TCC's proposed sale of assets process, the PUCT has hired a consultant to advise TCC during the sale of the generation assets. TCC's sale of its generating assets will be subject to a review in the 2004 true-up proceeding.

In June 2003, we began actively seeking buyers for 4,497 megawatts of TCC's generating capacity in Texas. In order to sell these assets, TCC anticipates retiring first mortgage bonds by making open market purchases or defeasing the bonds. Bids were received for all of TCC's generating plants. In January 2004, TCC agreed to sell its 7.8% ownership interest in the Oklaunion Power Station to an unaffiliated third party for $43 million. The sale of TCC's remaining generation is pending. Additional regulatory approvals will be required to complete the sale of the generation assets including NRC approval of the transfer of our interest in STP.

In the 2004 true-up proceeding, the amount of stranded costs under this market valuation methodology will be the amount by which the book value of TCC's generating assets, including regulatory assets and liabilities that were

not securitized and reduced by mitigation including unrefunded excess earnings, exceeds the market value of the generation assets as measured by the net proceeds from the sale of the assets. It is anticipated that any such sale will result in significant stranded costs for purposes of TCC's 2004 true-up proceeding.

After the 2004 true-up proceeding, TCC may seek to issue securitization revenue bonds for its stranded costs and recover the costs of the securitization bonds through transmission and distribution rates. Based upon the Oklaunion sale and the bid information for the remaining generation, we recorded an impairment of generating assets of $938 million in December 2003 as a regulatory asset (see Note 10). The recovery of the regulatory asset will be subject to review and approval by the PUCT as a stranded cost in the 2004 true-up proceeding.

Wholesale Capacity Auction True-up

Texas Legislation also requires that electric utilities and their affiliated power generation companies (PGC) offer for sale at auction, in 2002 and 2003 and after, at least 15% of the PGC's Texas jurisdictional installed generation capacity in order to promote competitiveness in the wholesale market through increased availability of generation. Actual market power prices received in the state mandated auctions will be used to calculate the wholesale capacity auction true-up adjustment for TCC for the 2004 true-up proceeding.

TCC recorded a $480 million regulatory asset and related revenues which represent the quantifiable amount of the wholesale capacity auction true-up for the years 2002 and 2003. In TCC's UCOS proceeding, the PUCT estimated that TCC had negative stranded costs. In its true-up rule, the PUCT determined that the wholesale capacity auction true-up proceeds should be offset against negative stranded costs. However, in March 2003, the Texas Court of Appeals ruled that under the restructuring legislation, other 2004 true-up items, including the wholesale capacity auction true-up regulatory asset, could be recovered regardless of the level of stranded costs.

In the fourth quarter of 2003, the PUCT approved a true-up filing package containing calculation instructions similar to the methodology employed by TCC to calculate the amount recorded for recovery under its wholesale capacity auction true-up. The PUCT will review the $480 million wholesale capacity regulatory asset for recovery as part of the 2004 true-up proceeding.

Fuel Balance Recoveries

In 2002, TNC filed with the PUCT seeking to reconcile fuel costs and to establish its deferred unrecovered fuel balance applicable to retail sales within its ERCOT service area for inclusion in the 2004 true-up proceeding. In January 2004, the PUCT announced a final ruling in TNC's fuel reconciliation case that established TNC's unrecovered fuel balance, including interest for the ERCOT service territory, at $6.2 million. This balance will be included in TNC's 2004 true-up proceeding. TNC is waiting for a written order from the PUCT, after which it will request a rehearing.

In 2002, TCC filed with the PUCT to reconcile fuel costs and to establish its deferred over-recovery of fuel balance for inclusion in the 2004 true-up proceeding. In February 2004, an ALJ issued recommendations finding a $205 million over recovery in this fuel proceeding. Management is unable to predict the amount of TCC's fuel over-recovery which will be included in its 2004 true-up proceeding.

See TCC Fuel Reconciliation and TNC Fuel Reconciliation in Note 4 "Rate Matters" for further discussion.

Unrefunded Excess Earnings

The Texas Legislation provides for the calculation of excess earnings for each year from 1999 through 2001. The total excess earnings determined for the three year period were $3 million for SWEPCo, $47 million for TCC and $19 million for TNC. TCC, TNC and SWEPCo challenged the PUCT's treatment of fuel-related deferred income taxes and appealed the PUCT's final 2000 excess earnings to the Travis County District Court which upheld the PUCT ruling. The District Court's ruling was appealed to the Third Court of Appeals. In August 2003, the Third Court of Appeals reversed the PUCT order and the District Court judgment. The PUCT's request for rehearing of the Appeals Court's decision was denied and the PUCT chose not to appeal the ruling any further. Appeal of the same issue from the PUCT's 2001 order is pending before the District Court. Since an expense and regulatory

liability had been accrued in prior years in compliance with the PUCT orders, the companies reversed a portion of their regulatory liability for the years 2000 and 2001 consistent with the Appeals Court's decision and credited amortization expense during the third quarter of 2003. Pre-tax amounts reversed by company were $5 million for TCC, $3 million for TNC and $1 million for SWEPCo.

In 2001, the PUCT issued an order requiring TCC to return estimated excess earnings by reducing distribution rates by approximately $55 million plus accrued interest over a five-year period beginning January 1, 2002. Since excess earnings amounts were expensed in 1999, 2000 and 2001, the order has no additional effect on reported net income but will reduce cash flows for the five-year refund period. The amount to be refunded is recorded as a regulatory liability. Management believes that TCC will have stranded costs and that it was inappropriate for the PUCT to order a refund prior to TCC's 2004 true-up proceeding. TCC appealed the PUCT's refund of excess earnings to the Travis County District Court. That court affirmed the PUCT's decision and further ordered that the refunds be provided to customers. TCC has appealed the decision to the Court of Appeals.

Retail Clawback

The Texas Legislation provides for the affiliated PTB REP serving residential and small commercial customers to refund to its T&D utility the excess of the PTB revenues over market prices (subject to certain conditions and a limitation of $150 per customer). This is the retail clawback. If, prior to January 1, 2004, 40% of the load for the residential or small commercial classes is served by competitive REPs, the retail clawback is not applicable for that class of customer. During 2003, TCC and TNC filed to notify the PUCT that competitive REPs serve over 40% of the load in the small commercial class. The PUCT approved TCC's and TNC's filings in December 2003. In 2002, AEP had accrued a regulatory liability of approximately $9 million for the small commercial retail clawback on its REP's books. When the PUCT certified that the REP's in TCC and TNC service territories had reached the 40% threshold, the regulatory liability was no longer required for the small commercial class and was reversed in December 2003. At December 31, 2003, the remaining retail clawback liability was $45.5 million for TCC and $11.8 million for TNC.

When the 2004 true-up proceeding is completed, TCC intends to file to recover PUCT-approved stranded costs and other true-up amounts that are in excess of current securitized amounts, plus appropriate carrying charges and other true-up amounts, through non-bypassable competition transition charge in the regulated T&D rates. TCC may also seek to securitize certain of the approved stranded plant costs and regulatory assets that were not previously recovered through the non-bypassable transition charge. The annual costs of securitization are recovered through a non-bypassable rate surcharge collected by the T&D utility over the term of the securitization bonds.

In the event we are unable, after the 2004 true-up proceeding, to recover all or a portion of our stranded plant costs, generation-related regulatory assets, unrecovered fuel balances, wholesale capacity auction true-up regulatory assets, other restructuring true-up items and costs, it could have a material adverse effect on results of operations, cash flows and possibly financial condition.

MICHIGAN RESTRUCTURING – Affecting I&M

Customer choice commenced for I&M's Michigan customers on January 1, 2002. Effective with that date the rates on I&M's Michigan customers' bills for retail electric service were unbundled to allow customers the opportunity to evaluate the cost of generation service for comparison with other offers. I&M's total rates in Michigan remain unchanged and reflect cost of service. At December 31, 2003, none of I&M's customers have elected to change suppliers and no alternative electric suppliers are registered to compete in I&M's Michigan service territory.

Management has concluded that as of December 31, 2003 the requirements to apply SFAS 71 continue to be met since I&M's rates for generation in Michigan continue to be cost-based regulated.

ARKANSAS RESTRUCTURING – Affecting SWEPCo

In February 2003, Arkansas repealed customer choice legislation originally enacted in 1999. Consequently, SWEPCo's Arkansas operations reapplied SFAS 71 regulatory accounting, which had been discontinued in 1999.

The reapplication of SFAS 71 had an insignificant effect on results of operations and financial condition. As a result of reapplying SFAS 71, derivative contract gains/losses for transactions within AEP's traditional marketing area allocated to Arkansas will not affect income until settled. That is, such positions will be recorded on the balance sheet as either a regulatory asset or liability until realized.

WEST VIRGINIA RESTRUCTURING – Affecting APCo

APCo reapplied SFAS 71 for its West Virginia (WV) jurisdiction in the first quarter of 2003 after new developments during the quarter prompted an analysis of the probability of restructuring becoming effective.

In 2000, the WVPSC issued an order approving an electricity restructuring plan, which the WV Legislature approved by joint resolution. The joint resolution provided that the WVPSC could not implement the plan until the WV legislature made tax law changes necessary to preserve the revenues of state and local governments.

In the 2001 and 2002 legislative sessions, the WV Legislature failed to enact the required legislation that would allow the WVPSC to implement the restructuring plan. Due to this lack of legislative activity, the WVPSC closed two proceedings related to electricity restructuring during the summer of 2002.

In the 2003 legislative session, the WV Legislature failed to enact the required tax legislation. Also, legislation enacted in March 2003 clarified the jurisdiction of the WVPSC over electric generation facilities in WV. In March 2003, APCo's outside counsel advised us that restructuring in WV was no longer probable and confirmed facts relating to the WVPSC's jurisdiction and rate authority over APCo's WV generation. APCo has concluded that deregulation of the WV generation business is no longer probable and operations in WV meet the requirements to reapply SFAS 71.

Reapplying SFAS 71 in WV had an insignificant effect on results of operations and financial condition. As a result, derivative contract gains/losses related to transactions within AEP's traditional marketing area allocated to WV will not affect income until settled. That is, such positions will be recorded on the balance sheet as either a regulatory asset or liability until realized. Positions outside AEP's traditional marketing area will continue to be marked-to-market.

7. COMMITMENTS AND CONTINGENCIES

ENVIRONMENTAL

Federal EPA Complaint and Notice of Violation – Affecting APCo, CSPCo, I&M, and OPCo

The Federal EPA and a number of states alleged APCo, CSPCo, I&M, OPCo and other unaffiliated utilities modified certain units at coal-fired generating plants in violation of the NSRs of the CAA. The Federal EPA filed its complaints against AEP subsidiaries in U.S. District Court for the Southern District of Ohio. The court also consolidated a separate lawsuit, initiated by certain special interest groups, with the Federal EPA case. The alleged modifications relate to costs that were incurred at the generating units over a 20-year period.

Under the Clean Air Act, if a plant undertakes a major modification that directly results in an emissions increase, permitting requirements might be triggered and the plant may be required to install additional pollution control technology. This requirement does not apply to activities such as routine maintenance, replacement of degraded equipment or failed components, or other repairs needed for the reliable, safe and efficient operation of the plant. The Clean Air Act authorizes civil penalties of up to $27,500 per day per violation at each generating unit ($25,000 per day prior to January 30, 1997). In 2001, the District Court ruled claims for civil penalties based on activities that occurred more than five years before the filing date of the complaints cannot be imposed. There is no time limit on claims for injunctive relief.

On August 7, 2003, the District Court issued a decision following a liability trial in a case pending in the Southern District of Ohio against Ohio Edison Company, an unaffiliated utility. The District Court held that replacements of major boiler and turbine components that are infrequently performed at a single unit, that are performed with the assistance of outside contractors, that are accounted for as capital expenditures, and that require the unit to be taken

out of service for a number of months are not "routine" maintenance, repair, and replacement. The District Court also held that a comparison of past actual emissions to projected future emissions must be performed prior to any non-routine physical change in order to evaluate whether an emissions increase will occur, and that increased hours of operation that are the result of eliminating forced outages due to the repairs must be included in that calculation. Based on these holdings, the District Court ruled that all of the challenged activities in that case were not routine, and that the changes resulted in significant net increases in emissions for certain pollutants. A remedy trial is scheduled for July 2004.

Management believes that the Ohio Edison decision fails to properly evaluate and apply the applicable legal standards. The facts in the AEP case also vary widely from plant to plant. Further, the Ohio Edison decision is limited to liability issues, and provides no insight as to the remedies that might ultimately be ordered by the Court.

On August 26, 2003, the District Court for the Middle District of South Carolina issued a decision on cross-motions for summary judgment prior to a liability trial in a case pending against Duke Energy Corporation, an unaffiliated utility. The District Court denied all the pending motions, but set forth the legal standards that will be applied at the trial in that case. The District Court determined that Federal EPA bears the burden of proof on the issue of whether a practice is "routine maintenance, repair, or replacement" and on whether or not a "significant net emissions increase" results from a physical change or change in the method of operation at a utility unit. However, the Federal EPA must consider whether a practice is "routine within the relevant source category" in determining if it is "routine." Further, the Federal EPA must calculate emissions by determining first whether a change in the maximum achievable hourly emission rate occurred as a result of the change, and then must calculate any change in annual emissions holding hours of operation constant before and after the change. The Federal EPA has requested reconsideration of this decision, or in the alternative, certification of an interlocutory appeal to the Fourth Circuit Court of Appeals.

On June 24, 2003, the United States Court of Appeals for the 11th Circuit issued an order invalidating the administrative compliance order issued by the Federal EPA to the Tennessee Valley Authority for similar alleged violations. The 11th Circuit determined that the administrative compliance order was not a final agency action, and that the enforcement provisions authorizing the issuance and enforcement of such orders under the Clean Air Act are unconstitutional.

On June 26, 2003, the United States Court of Appeals for the District of Columbia Circuit granted a petition by the Utility Air Regulatory Group (UARG), of which the AEP subsidiaries are members, to reopen petitions for review of the 1980 and 1992 Clean Air Act rulemakings that are the basis for the Federal EPA claims in the AEP case and other related cases. On August 4, 2003, UARG filed a motion to separate and expedite review of their challenges to the 1980 and 1992 rulemakings from other unrelated claims in the consolidated appeal. The Circuit Court denied that motion on September 30, 2003. The central issue in these petitions concerns the lawfulness of the emissions increase test, as currently interpreted and applied by the Federal EPA in its utility enforcement actions. A decision by the D. C. Circuit Court could significantly impact further proceedings in the AEP case.

On August 27, 2003, the Administrator of the Federal EPA signed a final rule that defines "routine maintenance repair and replacement" to include "functionally equivalent equipment replacement." Under the new final rule, replacement of a component within an integrated industrial operation (defined as a "process unit") with a new component that is identical or functionally equivalent will be deemed to be a "routine replacement" if the replacement does not change any of the fundamental design parameters of the process unit, does not result in emissions in excess of any authorized limit, and does not cost more than twenty percent of the replacement cost of the process unit. The new rule is intended to have prospective effect, and will become effective in certain states 60 days after October 27, 2003, the date of its publication in the Federal Register, and in other states upon completion of state processes to incorporate the new rule into state law. On October 27, 2003 twelve states, the District of Columbia and several cities filed an action in the United States Court of Appeals for the District of Columbia Circuit seeking judicial review of the new rule. The UARG has intervened in this case. On December 24, 2003, the Circuit Court granted a motion from the petitioners to stay the effective date of this rule, which had been December 26, 2003.

Management is unable to estimate the loss or range of loss related to the contingent liability for civil penalties under the CAA proceedings. Management is also unable to predict the timing of resolution of these matters due to

the number of alleged violations and the significant number of issues yet to be determined by the Court. If the AEP System companies do not prevail, any capital and operating costs of additional pollution control equipment that may be required, as well as any penalties imposed, would adversely affect future results of operations, cash flows and possibly financial condition unless such costs can be recovered through regulated rates and market prices for electricity.

In December 2000, Cinergy Corp., an unaffiliated utility, which operates certain plants jointly owned by CSPCo, reached a tentative agreement with the Federal EPA and other parties to settle litigation regarding generating plant emissions under the Clean Air Act. Negotiations are continuing between the parties in an attempt to reach final settlement terms. Cinergy's settlement could impact the operation of Zimmer Plant and W.C. Beckjord Generating Station Unit 6 (owned 25.4% and 12.5%, respectively, by CSPCo). Until a final settlement is reached, CSPCo will be unable to determine the settlement's impact on its jointly owned facilities and its future results of operations and cash flows.

NUCLEAR

Nuclear Plants – Affecting I&M and TCC

I&M owns and operates the two-unit 2,110 MW Cook Plant under licenses granted by the NRC. TCC owns 25.2% of the two-unit 2,500 MW STP. STPNOC operates STP on behalf of the joint owners under licenses granted by the NRC. The operation of a nuclear facility involves special risks, potential liabilities, and specific regulatory and safety requirements. Should a nuclear incident occur at any nuclear power plant facility in the U.S., the resultant liability could be substantial. By agreement I&M and TCC are partially liable together with all other electric utility companies that own nuclear generating units for a nuclear power plant incident at any nuclear plant in the U.S. In the event nuclear losses or liabilities are underinsured or exceed accumulated funds and recovery from customers is not possible, results of operations, cash flows and financial condition would be adversely affected.

Nuclear Incident Liability – Affecting I&M and TCC

The Price-Anderson Act establishes insurance protection for public liability arising from a nuclear incident at $10.6 billion and covers any incident at a licensed reactor in the U.S. Commercially available insurance provides $300 million of coverage. In the event of a nuclear incident at any nuclear plant in the U.S., the remainder of the liability would be provided by a deferred premium assessment of $101 million on each licensed reactor in the U.S. payable in annual installments of $10 million. As a result, I&M could be assessed $202 million per nuclear incident payable in annual installments of $20 million. TCC could be assessed $50 million per nuclear incident payable in annual installments of $5 million as its share of a STPNOC assessment. The number of incidents for which payments could be required is not limited. Under an industry-wide program insuring workers at nuclear facilities, I&M and TCC are also obligated for assessments of up to $6 million and $2 million, respectively, for potential claims. These obligations will remain in effect until December 31, 2007.

Insurance coverage for property damage, decommissioning and decontamination at the Cook Plant and STP is carried by I&M and STPNOC in the amount of $1.8 billion each. I&M and STPNOC jointly purchase $1 billion of excess coverage for property damage, decommissioning and decontamination. Additional insurance provides coverage for extra costs resulting from a prolonged accidental outage. I&M and STPNOC utilize an industry mutual insurer for the placement of this insurance coverage. Participation in this mutual insurer requires a contingent financial obligation of up to $43 million for I&M and $2 million for TCC which is assessable if the insurer's financial resources would be inadequate to pay for losses.

The current Price-Anderson Act expired in August 2002. Its contingent financial obligations still apply to reactors licensed by the NRC as of its expiration date. It is anticipated that the Price-Anderson Act will be renewed in 2004 with increases in required third party financial protection for nuclear incidents.

SNF Disposal – Affecting I&M and TCC

Federal law provides for government responsibility for permanent SNF disposal and assesses nuclear plant owners fees for SNF disposal. A fee of one mill per KWH for fuel consumed after April 6, 1983 at Cook Plant and STP is

being collected from customers and remitted to the U.S. Treasury. Fees and related interest of $226 million for fuel consumed prior to April 7, 1983 at Cook Plant have been recorded as long-term debt. I&M has not paid the government the Cook Plant related pre-April 1983 fees due to continued delays and uncertainties related to the federal disposal program. At December 31, 2003, funds collected from customers towards payment of the pre-April 1983 fee and related earnings thereon are in external funds and exceed the liability amount. TCC is not liable for any assessments for nuclear fuel consumed prior to April 7, 1983 since the STP units began operation in 1988 and 1989.

Decommissioning and Low Level Waste Accumulation Disposal – Affecting I&M and TCC

Decommissioning costs are accrued over the service lives of the Cook Plant and STP. The licenses to operate the two nuclear units at Cook Plant expire in 2014 and 2017. In November 2003, I&M filed to extend the operating licenses of the two Cook Plant units for up to an additional 20 years. The review of the license extension application is expected to take at least two years. After expiration of the licenses, Cook Plant is expected to be decommissioned using the prompt decontamination and dismantlement (DECON) method. The estimated cost of decommissioning and low level radioactive waste accumulation disposal costs for Cook Plant ranges from $821 million to $1,080 million in 2003 nondiscounted dollars. The wide range is caused by variables in assumptions including the estimated length of time SNF may need to be stored at the plant site subsequent to ceasing operations. This, in turn, depends on future developments in the federal government's SNF disposal program. Continued delays in the federal fuel disposal program can result in increased decommissioning costs. I&M is recovering estimated Cook Plant decommissioning costs in its three rate-making jurisdictions based on at least the lower end of the range in the most recent decommissioning study at the time of the last rate proceeding. The amount recovered in rates for decommissioning the Cook Plant and deposited in the external fund was $27 million in 2003, 2002 and 2001.

The licenses to operate the two nuclear units at STP expire in 2027 and 2028. After expiration of the licenses, STP is expected to be decommissioned using the DECON method. TCC estimates its portion of the costs of decommissioning STP to be $289 million in 1999 nondiscounted dollars. TCC is accruing and recovering these decommissioning costs through rates based on the service life of STP at a rate of $8 million per year.

Decommissioning costs recovered from customers are deposited in external trusts. In 2003, 2002 and 2001, I&M deposited in its decommissioning trust an additional $12 million each year related to special regulatory commission approved funding for decommissioning of the Cook Plant. Trust fund earnings increase the fund assets and decrease the amount needed to be recovered from ratepayers. Decommissioning costs including interest, unrealized gains and losses and expenses of the trust funds are recorded in Other Operation expense for Cook Plant. For STP, nuclear decommissioning costs are recorded in Other Operation expense, interest income of the trusts are recorded in Nonoperating Income and interest expense of the trust funds are included in Interest Charges.

TCC's nuclear decommissioning trust asset and liability are included in held for sale amounts on its Consolidated Balance Sheet.

OPERATIONAL

Construction and Commitments – Affecting AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC

The AEP System has substantial construction commitments to support its operations. The following table shows the estimated construction expenditures by company for 2004 – 2006 including amounts for proposed environmental rules:

	(in millions)
AEGCo	$73.3
APCo	1,307.2
CSPCo	391.4
I&M	645.1
KPCo	153.3
OPCo	1,686.4
PSO	296.2
SWEPCo	414.3
TCC	531.2
TNC	179.9

AEP subsidiaries have entered into long-term contracts to acquire fuel for electric generation. The expiration date of the longest fuel contract is 2007 for APCo, 2005 for CSPCo, 2007 for I&M, 2005 for KPCo, 2012 for OPCo, 2014 for PSO and 2006 for SWEPCo. The contracts provide for periodic price adjustments and contain various clauses that would release us from our obligations under certain conditions.

I&M has unit contingent contracts to supply approximately 250 MW of capacity to unaffiliated entities through December 31, 2009. The commitment is pursuant to a unit power agreement requiring the delivery of energy only if the unit capacity is available.

Potential Uninsured Losses – Affecting AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including, but not limited to, liabilities relating to damage to the Cook Plant or STP and costs of replacement power in the event of a nuclear incident at the Cook Plant or STP. Future losses or liabilities which are not completely insured, unless recovered from customers, could have a material adverse effect on results of operations, cash flows and financial condition.

Power Generation Facility – Affecting OPCo

AEP has agreements with Juniper Capital L.P. (Juniper) for Juniper to develop, construct, and finance a non-regulated merchant power generation facility (Facility) near Plaquemine, Louisiana and lease the Facility to AEP. Juniper will own the Facility and lease it to AEP after construction is completed. AEP will sublease the Facility to The Dow Chemical Company (Dow).

Dow will use a portion of the energy produced by the Facility and sell the excess energy. OPCo has agreed to purchase up to approximately 800 MW of such excess energy from Dow. OPCo has also agreed to sell up to approximately 800 MW of energy to Tractebel Energy Marketing, Inc. (TEM) for a period of 20 years under a Power Purchase and Sale Agreement dated November 15, 2000 (PPA) at a price which is currently in excess of market. Beginning May 1, 2003, OPCo tendered replacement capacity, energy and ancillary services to TEM pursuant to the PPA which TEM rejected as non-conforming.

OPCo has entered an agreement with an affiliate that eliminates OPCo's market exposure related to the PPA. AEP has guaranteed this affiliate's performance under the agreement.

On September 5, 2003, TEM and AEP separately filed declaratory judgment actions in the United States District Court for the Southern District of New York. AEP alleges that TEM has breached the PPA, and is seeking a determination of OPCo's rights under the PPA. TEM alleges that the PPA never became enforceable or alternatively, that the PPA has already been terminated as the result of AEP breaches. If the PPA is deemed terminated or found to be unenforceable by the court, AEP could be adversely affected to the extent we are unable to find other purchasers of the power with similar contractual terms to the extent we do not fully recover claimed termination value damages from TEM. The corporate parent of TEM has provided a limited guaranty.

On November 18, 2003, the above litigation was suspended pending final resolution in arbitration of all issues pertaining to the protocols relating to the dispatching, operation and maintenance of the Facility and the sale and delivery of electric power products. In the arbitration proceedings, TEM basically argued that in the absence of mutually agreed upon protocols there was no commercially reasonable means to obtain or deliver the electric power products and therefore the PPA is not enforceable. TEM further argued that the creation of the protocols is not subject to arbitration. The arbitrator ruled in favor of TEM, on February 11, 2004, and concluded that the "creation of protocols" was not subject to arbitration, but did not rule upon the merits of TEM's claim that the PPA is not enforceable.

If commercial operation is not achieved for purposes of the PPA by April 30, 2004, TEM may claim that it can terminate the PPA and is owed liquidating damages of approximately $17.5 million. TEM may also claim that AEP is not entitled to receive any termination value for the PPA.

Merger Litigation – Affecting AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC

In 2002, the U.S. Court of Appeals for the District of Columbia ruled that the SEC failed to prove that the June 15, 2000 merger of AEP with CSW meets the requirements of the PUHCA and sent the case back to the SEC for further review. Specifically, the court told the SEC to revisit its conclusion that the merger met PUHCA requirements that utilities be "physically interconnected" and confined to a "single area or region."

In its June 2000 approval of the merger, the SEC agreed with AEP that the companies' systems are integrated because they have transmission access rights to a single high-voltage line through Missouri and also met the PUCHA's single region requirement because it is now technically possible to centrally control the output of power plants across many states. In its ruling, the appeals court said that the SEC failed to support and explain its conclusions that the integration and single region requirements are satisfied.

Management believes that the merger meets the requirements of the PUHCA and expects the matter to be resolved favorably.

Enron Bankruptcy –Affecting APCo, CSPCo, I&M, KPCo and OPCo

On October 15, 2002, certain subsidiaries of AEP filed claims against Enron and its subsidiaries in the bankruptcy proceeding filed by the Enron entities which are pending in the U.S. Bankruptcy Court for the Southern District of New York. At the date of Enron's bankruptcy, certain subsidiaries of AEP had open trading contracts and trading accounts receivables and payables with Enron. In addition, on June 1, 2001, AEP purchased Houston Pipe Line Company (HPL) from Enron. Various HPL related contingencies and indemnities from Enron remained unsettled at the date of Enron's bankruptcy. The timing of the resolution of the claims by the Bankruptcy Court is not certain.

In September 2003, Enron filed a complaint in the Bankruptcy Court against AEPES challenging AEP's offsetting of receivables and payables and related collateral across various Enron entities and seeking payment of approximately $125 million plus interest in connection with gas related trading transactions. We will assert our right to offset trading payables owed to various Enron entities against trading receivables due to several AEP subsidiaries. Management is unable to predict the outcome of this lawsuit or its impact on results of operations, cash flows or financial condition.

In December 2003, Enron filed a complaint in the Bankruptcy Court against AEPSC seeking approximately $93 million plus interest in connection with a transaction for the sale and purchase of physical power among Enron,

AEP and Allegheny Energy Supply, LLC during November 2001. Enron's claim seeks to unwind the effects of the transaction. AEP believes it has several defenses to the claims in the action being brought by Enron. Management is unable to predict the outcome of this lawsuit or its impact on results of operations, cash flows or financial condition.

During 2002 and 2001, AEP expensed a total of $53 million ($34 million net of tax) for our estimated loss from the Enron bankruptcy. The amounts for certain subsidiaries were:

Registrant	Amounts Expensed	Amounts Net of Tax
	(in millions)	
APCo	$5.3	$3.4
CSPCo	2.7	1.8
I&M	2.8	1.8
KPCo	1.1	0.7
OPCo	3.6	2.3

The amount expensed was based on an analysis of contracts where AEP and Enron entities are counterparties, the offsetting of receivables and payables, the application of deposits from Enron entities and management's analysis of the HPL related purchase contingencies and indemnifications. As noted above, Enron has challenged the offsetting of receivables and payables. Management is unable to predict the final resolution of these disputes, however the impact on results of operations, cash flows and financial condition could be material.

Texas Commercial Energy, LLP Lawsuit – Affecting TCC and TNC

Texas Commercial Energy, LLP (TCE), a Texas REP, filed a lawsuit in federal District Court in Corpus Christi, Texas, in July 2003, against AEP and four AEP subsidiaries, including TCC and TNC, certain unaffiliated energy companies and ERCOT. The action alleges violations of the Sherman Antitrust Act, fraud, negligent misrepresentation, breach of fiduciary duty, breach of contract, civil conspiracy and negligence. The allegations, not all of which are made against the AEP companies, range from anticompetitive bidding to withholding power. TCE alleges that these activities resulted in price spikes requiring TCE to post additional collateral and ultimately forced it into bankruptcy when it was unable to raise prices to its customers due to fixed price contracts. The suit alleges over $500 million in damages for all defendants and seeks recovery of damages, exemplary damages and court costs. Two additional parties, Utility Choice, LLC and Cirro Energy Corporation, have sought leave to intervene as plaintiffs asserting similar claims. AEP and its subsidiaries filed a Motion to Dismiss in September 2003. In February 2004, TCE filed an amended complaint. AEP and its subsidiaries intend to file a motion to dismiss the amended complaint and otherwise vigorously defend against the claims.

Energy Market Investigation – Affecting AEP System

AEP and other energy market participants received data requests, subpoenas and requests for information from the FERC, the SEC, the PUCT, the U.S. Commodity Futures Trading Commission (CFTC), the U.S. Department of Justice and the California attorney general during 2002. Management responded to the inquiries and provided the requested information and has continued to respond to supplemental data requests in 2003 and 2004.

In March 2003, we received a subpoena from the SEC as part of the SEC's ongoing investigation of energy trading activities. In August 2002, we had received an informal data request from the SEC asking that we voluntarily provide information. The subpoena sought additional information and is part of the SEC's formal investigation. We responded to the subpoena and will continue to cooperate with the SEC.

On September 30, 2003, the CFTC filed a complaint against AEP and AEPES in federal district court in Columbus, Ohio. The CFTC alleges that AEP and AEPES provided false or misleading information about market conditions and prices of natural gas in an attempt to manipulate the price of natural gas in violation of the Commodity Exchange Act. The CFTC seeks civil penalties, restitution and disgorgement of benefits. The case is in the initial

pleading stage with our response to the complaint currently due on May 18, 2004. Although management is unable to predict the outcome of this case, it is not expected to have a material effect on results of operations due to a provision recorded in December 2003.

In January 2004, the CFTC issued a request for documents and other information in connection with a CFTC investigation of activities affecting the price of natural gas in the fall of 2003. We are responding to that request.

Management cannot predict what, if any further action, any of these governmental agencies may take with respect to these matters.

FERC Proposed Standard Market Design – Affecting AEP System

In July 2002, the FERC issued its Standard Market Design (SMD) notice of proposed rulemaking which sought to standardize the structure and operation of wholesale electricity markets across the country. Key elements of FERC's proposal included standard rules and processes for all users of the electricity transmission grid, new transmission rules and policies, and the creation of certain markets to be operated by independent administrators of the grid in all regions. The FERC issued a "white paper" on the proposal in April 2003, in response to the numerous comments FERC received on its proposal. Management does not know if or when the FERC will finalize a rule for SMD. Until the potential rule is finalized, management cannot predict its effect on cash flows and results of operations.

FERC Market Power Mitigation – Affecting AEP System

A FERC order issued in November 2001 on AEP's triennial market based wholesale power rate authorization update required certain mitigation actions that AEP would need to take for sales/purchases within its control area and required AEP to post information on its website regarding its power system's status. As a result of a request for rehearing filed by AEP and other market participants, FERC issued an order delaying the effective date of the mitigation plan until after a planned technical conference on market power determination. In December 2003, the FERC issued a staff paper discussing alternatives and held a technical conference in January 2004. Management is unable to predict the timing of any further action by the FERC or its affect of future results of operations and cash flows.

8. GUARANTEES

There are no liabilities recorded for guarantees entered into prior to December 31, 2002 by registrant subsidiaries in accordance with FIN 45. There are certain immaterial liabilities recorded for guarantees entered into subsequent to December 31, 2002. There is no collateral held in relation to any guarantees and there is no recourse to third parties in the event any guarantees are drawn unless specified below.

Letters of Credit

Certain registrant subsidiaries have entered into standby letters of credit (LOC) with third parties. These LOCs cover gas and electricity risk management contracts, construction contracts, insurance programs, security deposits, debt service reserves, and credit enhancements for issued bonds. All of these LOCs were issued in the registrant subsidiaries' ordinary course of business. At December 31, 2003, the maximum future payments of the LOCs include $43 million, $1 million, $5 million and $4 million for TCC, I&M, OPCo and SWEPCo, respectively, with maturities ranging from March 2004 to November 2005. AEP holds all assets of the subsidiaries as collateral. There is no recourse to third parties in the event these letters of credit are drawn.

SWEPCo

In connection with reducing the cost of the lignite mining contract for its Henry W. Pirkey Power Plant, SWEPCo has agreed under certain conditions, to assume the obligations under capital lease obligations and term loan payments of the mining contractor, Sabine Mining Company (Sabine). In the event Sabine defaults under any of these agreements, SWEPCo's total future maximum payment exposure is approximately $58 million with maturity dates ranging from June 2005 to February 2012.

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo has agreed to provide guarantees of mine reclamation in the amount of approximately $85 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by a third party miner. At December 31, 2003, the cost to reclaim the mine in 2035 is estimated to be approximately $36 million. This guarantee ends upon depletion of reserves estimated at 2035 plus 6 years to complete reclamation.

On July 1, 2003, SWEPCo consolidated Sabine due to the application of FIN 46 (see Note 2). Upon consolidation, SWEPCo recorded the assets and liabilities of Sabine ($78 million). Also, after consolidation, SWEPCo currently records all expenses (depreciation, interest and other operation expense) of Sabine and eliminates Sabine's revenues against SWEPCo's fuel expenses. There is no cumulative effect of an accounting change recorded as a result of the requirement to consolidate, and there is no change in net income due to the consolidation of Sabine.

Indemnifications and Other Guarantees

All of the registrant subsidiaries enter into certain types of contracts, which would require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. Registrant subsidiaries cannot estimate the maximum potential exposure for any of these indemnifications entered into prior to December 31, 2002 due to the uncertainty of future events. In 2003 registrant subsidiaries entered into sale agreements which included indemnifications with a maximum exposure that was not significant for any individual registrant subsidiary. There are no material liabilities recorded for any indemnifications entered into during 2003. There are no liabilities recorded for any indemnifications entered prior to December 31, 2002.

Certain registrant subsidiaries lease certain equipment under a master operating lease. Under the lease agreement, the lessor is guaranteed to receive up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair market value of the leased equipment is below the unamortized balance at the end of the lease term, we have committed to pay the difference between the fair market value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. At December 31, 2003, the maximum potential loss by subsidiary for these lease agreements assuming the fair market value of the equipment is zero at the end of the lease term is as follows:

Subsidiary	Maximum Potential Loss (in millions)
APCo	$ 1
CSPCo	1
I&M	2
KPCo	1
OPCo	3
PSO	4
SWEPCo	4
TCC	6
TNC	2

See Note 15 "Leases" for disclosure of lease residual value guarantees.

9. SUSTAINED EARNINGS IMPROVEMENT INITIATIVE

In response to difficult conditions in AEP's business, a Sustained Earnings Improvement (SEI) initiative was undertaken company-wide in the fourth quarter of 2002, as a cost-saving and revenue-building effort to build long-term earnings growth.

The registrant subsidiaries recorded termination benefits expense relating to 389 terminated employees totaling $57.9 million pre-tax in the fourth quarter of 2002. Of this amount, the registrant subsidiaries paid $5.0 million to

these terminated employees in the fourth quarter of 2002. No additional termination benefits expense related to the SEI initiative was recorded in 2003, and the remaining SEI related payments were made in 2003. The termination benefits expense is classified as Other Operation expense on the registrant subsidiaries' statements of operations. We determined that the termination of the employees under our SEI initiative did not constitute a plan curtailment of any of our retirement benefit plans.

The following table shows the staff reductions, termination benefits expense and the remaining termination benefits expense accrual as of December 31, 2002:

	Total Number of Terminated Employees	Total Expense Recorded in 2002 (in millions)	Total Termination Benefits Accrued at 12/31/02 (in millions)
AEGCo	-	$ 0.3	$ 0.3
APCo	93	13.1	12.2
CSPCo	19	5.0	4.5
I&M	146	15.0	13.1
KPCo	16	2.6	2.5
OPCo	33	7.5	7.1
PSO	17	3.1	3.0
SWEPCo	8	3.3	3.1
TCC	37	6.0	5.5
TNC	20	2.0	1.6

10. ACQUISITIONS, DISPOSITIONS, IMPAIRMENTS, ASSETS HELD FOR SALE AND ASSETS HELD AND USED

ACQUISITIONS

2001

SWEPCo purchased the Dolet Hills mining operations and assumed the existing mine reclamation liabilities at its jointly owned lignite reserves in Louisiana during 2001. Management recorded the assets acquired and liabilities assumed at their estimated fair values in accordance with APB Opinion No. 16 and SFAS 141 as appropriate based on currently available information and on current assumptions as to future operations.

DISPOSITIONS

2003

Water Heater Assets – APCo, CSPCo, I&M, KPCo and OPCo

APCo, CSPCo, I&M, KPCo and OPCo participated in a program to lease electric water heaters to residential and commercial customers until a decision was reached in the fourth quarter of 2002 to discontinue the program and offer the assets for sale. We sold our water heater rental program and recorded a pre-tax loss in the first quarter of 2003 based upon final terms of the sale agreement. We provided for pre-tax charges in the fourth quarter 2002 based on an estimated sales price. See below for amounts by company:

Subsidiary Company	Asset Impairment Charge Recorded in Fourth Quarter 2002 (Pre-tax)	Lease Prepayment Penalty Recorded in Fourth Quarter 2002 (Pre-tax) (in millions)	Loss on Sale Recorded in First Quarter 2003 (Pre-tax)
APCo	$0.050	$0.062	$0.056
CSPCo	0.615	0.758	0.740
I&M	0.643	0.792	0.787
KPCo	0.011	0.011	0.011
OPCo	1.757	2.163	2.165

Ft. Davis Wind Farm – TNC

In the 1990's TNC developed a 6MW facility wind energy project located on a lease site near Ft. Davis, Texas. In the fourth quarter of 2002 TNC's engineering staff determined that operation of the facility was no longer technically feasible and the lease of the underlying site should not be renewed. Dismantling of the facility is expected to be completed during 2004. An estimated pre-tax loss on abandonment of $4.7 million was recorded in December 2002. The loss was recorded in Asset Impairments on TNC's Statements of Operations.

2001

Coal Mines – OPCo

In July 2001, OPCo sold coal mines in Ohio and West Virginia and agreed to purchase approximately 34 million tons of coal from the purchaser of the mines through 2008. The sale had a nominal impact on OPCo's results of operations and cash flows.

ASSETS HELD FOR SALE

Texas Plants – TCC and TNC

In September 2002, AEP indicated to ERCOT its intent to deactivate 16 gas-fired power plants (8 TCC plants and 8 TNC plants). ERCOT subsequently conducted reliability studies, which determined that seven plants (4 TCC plants and 3 TNC plants) would be required to ensure reliability of the electricity grid. As a result of those studies, ERCOT and AEP mutually agreed to enter into reliability must run (RMR) agreements, which expired in December 2002, and were subsequently renewed through December 2003. However, certain contractual provisions provided ERCOT with a 90-day termination clause, if the contracted facility was no longer needed to ensure reliability of the electricity grid. With ERCOT's approval, AEP proceeded with its planned deactivation of the remaining nine plants. In August 2003, pursuant to contractual terms, ERCOT provided notification to AEP of its intent to cancel a RMR agreement at one of the TNC plants. Upon termination of the agreement, AEP proceeded with its planned deactivation of the plant. In December 2003, AEP and ERCOT mutually agreed to new RMR contracts at six plants (4 TCC plants and 2 TNC plants) through December 2004, subject to ERCOT's 90-day termination clause and the divestiture of the TCC facilities.

As a result of the decision to deactivate TNC plants, a write-down of utility assets of approximately $34.2 million (pre-tax) was recorded in Asset Impairments expense during the third quarter 2002 on TNC's Statements of Operations. The decision to deactivate the TCC plants resulted in a write-down of utility assets of approximately $95.6 million (pre-tax), which was deferred and recorded in Regulatory Assets during the third quarter 2002 in TCC's Consolidated Balance Sheets.

During the fourth quarter 2002, evaluations continued as to whether assets remaining at the deactivated plants, including materials, supplies and fuel oil inventories, could be utilized elsewhere within the AEP System. As a result of such evaluations, TNC recorded an additional asset impairment charge to Asset Impairments expense of $3.9 million (pre-tax) in the fourth quarter 2002. In addition, TNC recorded related inventory write-downs of $2.6 million ($1.2 million of fuel inventory in Fuel for Electric Generation expense and $1.4 million of materials and supplies recorded in Other Operation expense). Similarly, TCC recorded an additional asset impairment write-down of $6.7 million (pre-tax), which was deferred and recorded in Regulatory Assets Designated for Securitization in the fourth quarter 2002. TCC also recorded related inventory write-downs of $14.9 million which was deferred and recorded in Regulatory Assets in the fourth quarter 2002.

The total Texas plant asset impairment of $38.1 million in 2002 related to TNC is included in Asset Impairments expense in TNC's Statements of Operations.

In December 2002, TCC filed a plan of divestiture with the PUCT proposing to sell all of its power generation assets, including the eight gas-fired generating plants that were either deactivated or designated as RMR status. During the fourth quarter of 2003, after receiving bids from interested buyers, TCC recorded a $938 million impairment loss and changed the classification of the plant assets from plant in service to assets held for sale. In

accordance with Texas legislation, the $938 million impairment was offset by the establishment of a regulatory asset, which is expected to be recovered through a wires charge, subject to the final outcome of the 2004 Texas true-up proceeding. See Texas Restructuring section of Note 6 "Customer Choice and Industry Restructuring" for further discussion of the divestiture plan, anticipated timeline and true-up proceeding.

The assets and liabilities of the entities held for sale at December 31, 2003 and 2002 are as follows:

December 31, 2003	Texas Plants (TCC) (in millions)
Assets:	
Current Assets	$57
Property, Plant and Equipment, Net	797
Regulatory Assets	49
Nuclear Decommissioning Trust Fund	125
Total Assets Held for Sale	$1,028
Liabilities:	
Regulatory Liabilities – Other	$9
Other Noncurrent Liabilities	219
Total Liabilities Held for Sale	$228

December 31, 2002	Texas Plants (TCC) (in millions)
Assets:	
Current Assets	$70
Property, Plant and Equipment, Net	1,647
Nuclear Decommissioning Trust Fund	98
Total Assets Held for Sale	$1,815
Liabilities:	
Deferred Credits and Other	$9
Total Liabilities Held for Sale	$9

ASSETS HELD AND USED

Blackhawk Coal Company – I&M

Blackhawk Coal Company (Blackhawk) is a wholly-owned subsidiary of I&M and was formerly engaged in coal mining operations until they ceased due to gas explosions in the mine. During the fourth quarter of 2003, it was determined that the value of the investment needed to be written down based on an updated valuation reflecting management's decision not to pursue development of potential gas reserves. As a result, a $10.4 million charge was recorded to reduce the value of the coal and gas reserves to their estimated realizable value. This charge was recorded in Nonoperating Expenses in I&M's Consolidated Statements of Income.

11. BENEFIT PLANS

APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC participate in AEP sponsored U.S. qualified pension plans and nonqualified pension plans. A substantial majority of employees are covered by either one qualified plan or both a qualified and a nonqualified pension plan. In addition, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWPECo, TCC and TNC participate in other postretirement benefit plans sponsored by AEP to provide medical and death benefits for retired employees in the U.S.

The following tables provide a reconciliation of the changes in the plans' benefit obligations and fair value of assets over the two-year period ending at the plan's measurement date of December 31, 2003, and a statement of the funded status as of December 31 for both years:

	U.S. Pension Plans		U.S. Other Post Retirement Benefit Plans	
	2003	2002	2003	2002
Change in Benefit Obligation:		(in millions)		
Obligation at January 1	$3,583	$3,292	$1,877	$1,645
Service Cost	80	72	42	34
Interest Cost	233	241	130	114
Participant Contributions	-	-	14	13
Plan Amendments	-	(2)	-	-
Actuarial (Gain) Loss	91	258	192	152
Benefit Payments	(299)	(278)	(92)	(81)
Obligation at December 31	$3,688	$3,583	$2,163	$1,877
Change in Fair Value of Plan Assets:				
Fair Value of Plan Assets at January 1	$2,795	$3,438	$723	$711
Actual Return on Plan Assets	619	(371)	122	(57)
Company Contributions (a)	65	6	183	137
Participant Contributions	-	-	14	13
Benefit Payments (a)	(299)	(278)	(92)	(81)
Fair Value of Plan Assets at December, 31	$3,180	$2,795	$950	$723
Funded Status:				
Funded Status at December 31	$(508)	$(788)	$(1,213)	$(1,154)
Unrecognized Net Transition (Asset) Obligation	2	(7)	206	233
Unrecognized Prior Service Cost	(12)	(13)	6	6
Unrecognized Actuarial (Gain) Loss	797	1,020	977	896
Net Asset (Liability) Recognized	$279	$212	$(24)	$(19)

(a) AEP contributions and benefit payments include only those amounts contributed directly to or paid directly from plan assets.

Accumulated Benefit Obligation:	2003	2002
	(in millions)	
U.S. Qualified Pension Plans	$3,549	$3,456
U.S. Nonqualified Pension Plans	76	71

	U.S. Pension Plans		U.S. Other Post Retirement Benefit Plans	
	2003	2002	2003	2002
		(in millions)		
Prepaid Benefit Costs	$325	$255	$-	$-
Accrued Benefit Liability	(46)	(44)	(24)	(19)
Additional Minimum Liability	(723)	(944)	N/A	N/A
Unrecognized Prior Service Costs	39	45	N/A	N/A
Accumulated Other Comprehensive Income	684	900	N/A	N/A
Net Asset (Liability) Recognized	$279	$212	$(24)	$(19)
Increase (Decrease) in Minimum Liability Included in Other Comprehensive Income (Pre-tax)	$(216)	$894	N/A	N/A

N/A = Not Applicable

The asset allocations for the U.S. pension plans at the end of 2003 and 2002, and the target allocation for 2004, by asset category, are as follows:

Asset Category	Target Allocation 2004	Percentage of Plan Assets at Yearend 2003	2002
		(in percentage)	
Equity	70	71	67
Fixed Income	28	27	32
Cash and Cash Equivalents	2	2	1
Total	100	100	100

The asset allocations for the U.S. other postretirement benefit plans at the end of 2003 and 2002, and target allocation for 2004, by asset category, are as follows:

Asset Category	Target Allocation 2004	Percentage of Plan Assets at Yearend 2003	2002
		(in percentage)	
Equity	70	61	41
Fixed Income	28	36	38
Cash and Cash Equivalents	2	3	21
Total	100	100	100

AEP's investment strategy for the employee benefit trust funds is to use a diversified mixture of equity and fixed income securities to preserve the capital of the funds and to maximize the investment earnings in excess of inflation within acceptable levels of risk.

The value of the AEP qualified plans' assets increased from $2.795 billion at December 31, 2002 to $3.180 billion at December 31, 2003. The qualified plans paid $292 million in benefits to plan participants during 2003 (nonqualified plans paid $7 million in benefits). AEP's plans remain in an underfunded position (plan assets are less than projected benefit obligations) of $508 million at December 31, 2003. Due to the pension plans currently being underfunded, AEP recorded income in Other Comprehensive Income (OCI) of $154 million, and a reduction in the Deferred Income Tax Asset of $76 million, offset by a reduction to Minimum Pension Liability of $234 million and a reduction in adjustments for unrecognized costs of $4 million. The charge to OCI does not affect earnings or cash flow. Also, due to the current underfunded status of AEP's qualified plans, AEP expects to make cash contributions to the U.S. pension plans of approximately $41 million in 2004.

At December 31, 2003 and 2002, the projected benefit obligation, accumulated benefit obligation, and fair value of U.S. plan assets of the U.S. pension plans with an accumulated benefit obligation in excess of plan assets, were as follows:

	U.S. Plans	
End of Year	2003	2002
	(in millions)	
Projected Benefit Obligation	$3,688	$3,583
Accumulated Benefit Obligation	3,625	3,527
Fair Value of Plan Assets	3,180	2,795
Accumulated Benefit Obligation Exceeds the Fair Value of Plan Assets	445	732

AEP bases its determination of pension expense or income on a market-related valuation of assets which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the market-related value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded.

The weighted-average assumptions as of December 31, used in the measurement of AEP's benefit obligations are shown in the following tables:

	U.S. Pension Plans		U.S. Other Postretirement Benefit Plans	
	2003	2002	2003	2002
			(in percentage)	
Discount Rate	6.25	6.75	6.25	6.75
Rate of Compensation Increase	3.7	3.7	N/A	N/A

In determining the discount rate in the calculation of future pension obligations AEP reviews the interest rates of long-term bonds that receive one of the two highest ratings given by a recognized rating agency. As a result of a decrease in this benchmark rate during 2003, AEP determined that a decrease in its discount rate from 6.75% at December 31, 2002 to 6.25% at December 31, 2003 was appropriate.

The rate of compensation increase assumed varies with the age of the employee, ranging from 3.5% per year to 8.5% per year, with an average increase of 3.7%.

Information about the expected cash flows for the U.S. pension (qualified and non-qualified) and other postretirement benefit plans is as follows:

	U.S. Pension Plans	U.S. Other Postretirement Benefit Plans
	(in millions)	
Employer Contributions		
2003	$65	$183
2004 (expected)	41	180

The table below reflects the total benefits expected to be paid from the plan or from AEP assets, including both AEP's share of the benefit cost and the participants' share of the cost, which is funded by participant contributions to the plan. Future benefit payments are dependent on the number of employees retiring, whether the retiring employees elect to receive pension benefits as annuities or as lump sum distributions, future integration of the benefit plans with changes to Medicare and other legislation, future levels of interest rates, and variances in actuarial results. The estimated payments for pension benefits and other postretirement benefits are as follows:

	U.S. Pension Benefits	U.S. Other Postretirement Benefit Plans
	(in millions)	
2004	$293	$106
2005	300	114
2006	310	123
2007	325	132
2008	335	140
Years 2009 to 2013, in Total	1,840	836

The contribution to the pension fund is based on the minimum amount required by the U.S. Department of Labor or the amount of the pension expense for accounting purposes, whichever is greater. The contribution to the other postretirement benefit plans' trusts is generally based on the amount of the other postretirement benefit plans' expense for accounting purposes and is provided for in agreements with state regulatory authorities.

The following table provides the components of AEP's net periodic benefit cost (credit) for the plans for fiscal years 2003, 2002 and 2001:

	U.S. Pension Plans			U.S. Other Postretirement Benefit Plans		
	2003	2002	2001	2003	2002	2001
	(in millions)					
Service Cost	$80	$72	$69	$42	$34	$30
Interest Cost	233	241	232	130	114	114
Expected Return on Plan Assets	(318)	(337)	(338)	(64)	(62)	(61)
Amortization of Transition (Asset) Obligation	(8)	(9)	(8)	28	29	30
Amortization of Prior-service Cost	(1)	(1)	-	-	-	-
Amortization of Net Actuarial (Gain) Loss	11	(10)	(24)	52	27	18
Net Periodic Benefit Cost (Credit)	(3)	(44)	(69)	188	142	131
Curtailment Loss	-	-	-	-	-	1
Net Periodic Benefit Cost (Credit) After Curtailments	$(3)	$(44)	$(69)	$188	$142	$132

The following table provides the net periodic benefit cost (credit) for the plans by the following AEP registrant subsidiaries for fiscal years 2003, 2002 and 2001:

	Pension Plans			Other Postretirement Benefit Plans		
	2003	2002	2001	2003	2002	2001
	(thousands)					
APCo	$(5,202)	$(9,988)	$(13,645)	$33,618	$25,107	$22,810
CSPCo	(5,399)	(8,328)	(10,624)	14,684	11,494	10,328
I&M	(812)	(4,206)	(7,805)	22,999	17,608	15,077
KPCo	(566)	(1,406)	(1,922)	4,043	2,986	2,438
OPCo	(6,621)	(11,360)	(14,879)	28,143	22,608	34,444
PSO	(291)	(3,819)	(2,480)	9,885	8,436	6,187
SWEPCo	1,012	(2,245)	(3,051)	10,264	8,371	6,399
TCC	(123)	(4,786)	(3,411)	12,951	10,733	8,214
TNC	606	(1,104)	(1,644)	5,875	4,798	3,729

The weighted-average assumptions as of January 1, used in the measurement of AEP's benefit costs are shown in the following tables:

	U.S. Pension Plans			U.S. Other Postretirement Benefit Plans		
	2003	2002	2001	2003	2002	2001
	(in percentage)					
Discount Rate	6.75	7.25	7.50	6.75	7.25	7.50
Expected Return on Plan Assets	9.00	9.00	9.00	8.75	8.75	8.75
Rate of Compensation Increase	3.7	3.7	3.2	N/A	N/A	N/A

The expected return on plan assets for 2003 was determined by evaluating historical returns, the current investment climate, rate of inflation, and current prospects for economic growth. After evaluating the current yield on fixed income securities as well as other recent investment market indicators, the expected return on plan assets was reduced to 8.75% for 2004. The expected return on other postretirement benefit plan assets (a portion of which is subject to capital gains taxes as well as unrelated business income taxes) was reduced to 8.35%.

The assumptions used for other postretirement benefit plan measurement purposes are shown below:

Health Care Trend Rates:	2003	2002
	(in percentage)	
Initial	10.0	10.0
Ultimate	5.0	5.0
Year Ultimate Reached	2008	2008

Assumed health care cost trend rates have a significant effect on the amounts reported for the other postretirement benefit health care plans. A 1% change in assumed health care cost trend rates would have the following effects:

	1% Increase	1% Decrease
	(in millions)	
Effect on Total Service and Interest Cost Components of Net Periodic Postretirement Health Care Benefit Cost	$26	$(21)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	315	(257)

AEP has not yet determined the impact of the Medicare Prescription Drug Improvement and Modernization Act of 2003 on its other postretirement benefit plans' accumulated benefit obligation and periodic benefit cost. See FASB Staff Position No. 106-1 in Note 2 for additional information on the potential impact on AEP's results of operations, cash flows and financial condition.

Retirement Savings Plan

APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC participate in an AEP sponsored defined contribution retirement savings plan eligible to substantially all non-United Mine Workers of America (UMWA) employees. This plan includes features under Section 401(k) of the Internal Revenue Code and provides for company matching contributions. Prior to January 1, 2003, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC participated in two large AEP sponsored defined contribution retirement savings plans. Beginning in 2001 and continuing with the single merged plan, contributions to the plans increased from 50% to 75% of the first 6% of eligible employee compensation.

The following table provides the cost for contributions to the retirement savings plans by the following AEP registrant subsidiaries for fiscal years 2003, 2002 and 2001:

	2003	2002	2001
		(in thousands)	
APCo	$6,450	$ 6,722	$7,031
CSPCo	2,745	2,784	2,789
I&M	7,616	8,039	7,833
KPCo	1,042	1,043	1,016
OPCo	5,719	5,785	6,398
PSO	2,350	2,260	2,235
SWEPCo	3,418	3,170	2,896
TCC	2,757	3,054	3,046
TNC	1,332	1,574	1,558

Other UMWA Benefits

OPCo provides UMWA pension, health and welfare benefits for certain unionized mining employees, retirees, and their survivors who meet eligibility requirements. UWMA trustees make final interpretive determinations with regard to all benefits. The pension benefits are administered by UMWA trustees and contributions are made to their trust funds. The health and welfare benefits are administered by AEP and benefits are paid from AEP's general assets. Contributions are expensed as paid as part of the cost of active mining operations and were not material in 2003, 2002 and 2001. In July 2001, OPCo sold certain coal mines in Ohio and West Virginia.

12. BUSINESS SEGMENTS

All of AEP's registrant subsidiaries have one reportable segment. The one reportable segment is a vertically integrated electricity generation, transmission and distribution business except AEGCo, an electricity generation business. All of the registrants' other activities are insignificant. The registrant subsidiaries' operations are managed on an integrated basis because of the substantial impact of bundled cost-based rates and regulatory oversight on the business process, cost structures and operating results.

13. DERIVATIVES, HEDGING AND FINANCIAL INSTRUMENTS

Derivatives and Hedging

In the first quarter of 2001, we adopted SFAS 133, "Accounting for Derivative Instruments and Hedging Activities," as amended. Registrant Subsidiaries recorded a transition adjustment to Accumulated Other Comprehensive Income (Loss) on January 1, 2001 in connection with the adoption of SFAS 133. Derivatives included in the transition adjustment are interest rate swaps, foreign currency swaps and commodity swaps, options and futures.

SFAS 133 requires recognition of all derivative instruments as either assets or liabilities in the statement of financial position at fair value. Registrant subsidiaries accounting for the changes in the fair value of a derivative instrument depends on whether it qualifies, and has been designated, as part of a hedging relationship and further, on the type of hedging relationship. Registrant subsidiaries designate the hedging instrument, based on the exposure being hedged, as a fair value hedge or a cash flow hedge. Certain qualifying derivative instruments have been designated as normal purchase or normal sale contracts, as provided in SFAS 133. These contracts are not reported at fair value, as otherwise required by SFAS 133.

For fair value hedges (i.e. hedging the exposure to changes in the fair value of an asset, liability or an identified portion thereof that is attributable to a particular risk), registrant subsidiaries recognize the gain or loss on the derivative instrument as well as the offsetting loss or gain on the hedged item associated with the hedged risk in Revenues in the Consolidated Statements of Operations during the period of change. For cash flow hedges (i.e., hedging the exposure to variability in expected future cash flows that is attributable to a particular risk), registrant

subsidiaries initially report the effective portion of the gain or loss on the derivative instrument as a component of Other Accumulated Comprehensive Income and subsequently reclassify it to Revenues in the Consolidated Statements of Operations when the forecasted transaction affects earnings. The remaining gain or loss on the derivative instrument in excess of the cumulative change in the present value of future cash flows of the hedged item, if any, is recognized currently in revenues during the period of change. Registrant subsidiaries recognize any ineffective portions of in revenues immediately during the period of change.

Fair Value Hedging Strategies

Certain registrant subsidiaries enter into interest rate forward and swap transactions for interest rate risk exposure management purposes. The interest rate forward and swap transactions effectively modifies our exposure to interest risk by converting a portion of our fixed-rate debt to a floating rate. Registrant subsidiaries do not hedge all interest rate exposure.

Cash Flow Hedging Strategies

Certain registrant subsidiaries enter into forward contracts to protect against the reduction in value of forecasted cash flows resulting from transactions denominated in foreign currencies. When the dollar strengthens significantly against the foreign currencies, the decline in value of future foreign currency revenue is offset by gains in the value of the forward contracts designated as cash flow hedges. Conversely, when the dollar weakens, the increase in the value of future foreign currency cash flows is offset by losses in the value of forward contracts. Registrant subsidiaries do not hedge all foreign currency exposure.

Certain registrant subsidiaries enter into interest rate forward and swap transactions in order to manage interest rate risk exposure. These transactions effectively modify our exposure to interest risk by converting a portion of our floating-rate debt to a fixed rate. Registrant subsidiaries do not hedge all interest rate exposure.

Registrant subsidiaries enter into forward and swap transactions for the purchase and sale of electricity to manage the variable price risk related to the forecasted purchase and sale of electricity. We closely monitor the potential impact of commodity price changes and, where appropriate, enter into contracts to protect margin for a portion of future sales and generation revenues. Registrant Subsidiaries do not hedge all variable price risk exposure related to the forecasted purchase and sale of electricity.

The following table represents the activity in Accumulated Other Comprehensive Income (Loss) related to the effect of adopting SFAS 133 for derivative contracts that qualify as cash flow hedges at December 31, 2003:

	(in thousands)
APCo	
Beginning Balance, January 1, 2003	$(1,920)
Effective portion of changes in fair value	(448)
Reclasses from AOCI to net income	799
Ending Balance, December 31, 2003	$(1,569)
CSPCo	
Beginning Balance, January 1, 2003	$(267)
Effective portion of changes in fair value	194
Reclasses from AOCI to net income	275
Ending Balance, December 31, 2003	$202
I&M	
Beginning Balance, January 1, 2003	$(286)
Effective portion of changes in fair value	209
Reclasses from AOCI to net income	299
Ending Balance, December 31, 2003	$222

KPCo	
Beginning Balance, January 1, 2003	$322
Effective portion of changes in fair value	75
Reclasses from AOCI to net income	23
Ending Balance, December 31, 2003	$420
OPCo	
Beginning Balance, January 1, 2003	$(738)
Effective portion of changes in fair value	256
Reclasses from AOCI to net income	379
Ending Balance, December 31, 2003	$(103)
PSO	
Beginning Balance, January 1, 2003	$(42)
Effective portion of changes in fair value	18
Reclasses from AOCI to net income	180
Ending Balance, December 31, 2003	$156
SWEPCo	
Beginning Balance, January 1, 2003	$(48)
Effective portion of changes in fair value	21
Reclasses from AOCI to net income	211
Ending Balance, December 31, 2003	$184
TCC	
Beginning Balance, January 1, 2003	$(36)
Effective portion of changes in fair value	(1,931)
Reclasses from AOCI to net income	139
Ending Balance, December 31, 2003	$(1,828)
TNC	
Beginning Balance, January 1, 2003	$(15)
Effective portion of changes in fair value	(641)
Reclasses from AOCI to net income	55
Ending Balance, December 31, 2003	$(601)

The following table approximates net gain (losses) from cash flow hedges in Accumulated Other Comprehensive Income (Loss) at December 31, 2003 that are expected to be reclassified to net income in the next twelve months as the items being hedged settle. The actual amounts reclassified from AOCI to Net Income can differ as a result of market price changes. The maximum term for which the exposure to the variability of future cash flows is being hedged is five years.

	(in thousands)
APCo	$1,325
CSPCo	940
I&M	1,031
KPCo	466
OPCo	1,231
PSO	724
SWEPCo	853
TCC	(1,413)
TNC	(435)

Financial Instruments

Market Valuation of Non-Derivative Financial Instrument

The fair values of Long-term Debt and preferred stock subject to mandatory redemption are based on quoted market prices for the same or similar issues and the current dividend or interest rates offered for instruments with similar maturities. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that could be realized in a current market exchange. The book values and fair values of significant financial instruments for registrant subsidiaries at December 31, 2003 and 2002 are summarized in the following tables.

	2003		2002	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)		(in thousands)	
AEGCo				
Long-term Debt	$44,811	$47,882	$44,802	$48,103
APCo				
Long-term Debt	$1,864,081	$1,926,518	$1,893,861	$1,953,087
Cumulative Preferred Stock Subject to Mandatory Redemption (a)	5,360	5,287	10,860	9,774
CSPCo				
Long-term Debt	$897,564	$938,595	$621,626	$643,715
I&M				
Long-term Debt	$1,339,359	$1,400,937	$1,617,062	$1,673,363
Cumulative Preferred Stock Subject to Mandatory Redemption (a)	63,445	63,293	64,945	58,948
KPCo				
Long-term Debt	$427,602	$439,636	$466,632	$475,455
OPCo				
Long-term Debt	$2,039,940	$2,117,131	$1,067,314	$1,095,197
Cumulative Preferred Stock Subject to Mandatory Redemption (a)	7,250	7,214	8,850	7,965
PSO				
Long-term Debt	$574,298	$589,956	$545,437	$570,761
Trust Preferred Securities (b)	-	-	75,000	75,900
SWEPCo				
Long-term Debt	$884,308	$917,982	$693,448	$727,085
Trust Preferred Securities (b)	-	-	110,000	110,880
TCC				
Long-term Debt	$2,291,625	$2,393,468	$1,438,565	$1,522,373
Trust Preferred Securities (b)	-	-	136,250	136,959
TNC				
Long-term Debt	$356,754	$374,420	$132,500	$144,060

(a) See Registrants Statements of Capitalization for the effect of SFAS 150 in 2003.
(b) See Note 16 on Trust Preferred Securities.

Other Financial Instruments - Nuclear Trust Funds Recorded at Market Value

The trust investments are classified as available for sale for decommissioning (I&M, TCC) and SNJ disposal for I&M. I&M reports trusts in "Nuclear Decommissioning and Spent Nuclear Fuel Disposal Trust Funds" on the Consolidated Balance Sheets. TCC reports trusts in "Assets Held for Sale – Texas Generating Plants" on their Consolidated Balance Sheets. The following table provides fair values, cost basis and net unrealized gains or losses at December 31:

	I&M (in thousands)		TCC (in thousands)	
	2003	2002	2003	2002
Fair Value	$982,400	$870,700	$125,400	$98,400
Cost Basis	$900,000	$823,900	$94,800	$84,600

	I&M (in thousands)			TCC (in thousands)		
	2003	2002	2001	2003	2002	2001
Net Unrealized Holding Gain (Loss)	$35,500	$(25,400)	$(8,300)	$16,700	$(7,500)	$(3,000)

14. INCOME TAXES

The details of the registrant subsidiaries income taxes before extraordinary items and cumulative effect of accounting changes as reported are as follows:

Year Ended December 31, 2003 (in thousands)	AEGCo	APCo	CSPCo	I&M	KPCo
Charged (Credited) to Operating Expenses (net):					
Current	$7,481	$84,449	$83,469	$58,190	$(7,840)
Deferred	(5,838)	37,024	3,982	66	21,183
Deferred Investment Tax Credits	-	(1,884)	(3,041)	(7,330)	(1,168)
Total	1,643	119,589	84,410	50,926	12,175
Charged (Credited) to Nonoperating Income (net):					
Current	(196)	(646)	(2,183)	5,283	(1,382)
Deferred	-	(12,461)	(8,496)	(14,960)	(1,076)
Deferred Investment Tax Credits	(3,354)	(1,262)	(69)	(101)	(42)
Total	(3,550)	(14,369)	(10,748)	(9,778)	(2,500)
Total Income Tax as Reported	$(1,907)	$105,220	$73,662	$41,148	$9,675

Year Ended December 31, 2003	OPCo	PSO	SWEPCo	TCC	TNC
			(in thousands)		
Charged (Credited) to Operating Expenses (net):					
Current	$116,316	$55,834	$51,564	$88,530	$33,822
Deferred	32,191	(17,036)	7,230	14,769	(5,113)
Deferred Investment Tax Credits	(2,493)	(1,790)	(4,326)	(5,207)	(1,520)
Total	146,014	37,008	54,468	98,092	27,189
Charged (Credited) to Nonoperating Income (net):					
Current	708	(1,566)	(6,108)	2,456	1,454
Deferred	(7,709)	2,395	2,712	4,624	1,620
Deferred Investment Tax Credits	(614)	-	-	-	-
Total	(7,615)	829	(3,396)	7,080	3,074
Total Income Tax as Reported	$138,399	$37,837	$51,072	$105,172	$30,263

Year Ended December 31, 2002	AEGCo	APCo	CSPCo	I&M	KPCo
			(in thousands)		
Charged (Credited) to Operating Expenses (net):					
Current	$6,607	$99,140	$81,538	$66,063	$680
Deferred	(5,028)	17,626	25,771	(19,870)	9,451
Deferred Investment Tax Credits	2	(3,229)	(3,095)	(7,340)	(1,173)
Total	1,581	113,537	104,214	38,853	8,958
Charged (Credited) to Nonoperating Income (net):					
Current	(173)	(354)	9,442	3,435	1,583
Deferred	-	(849)	(2,479)	2,949	388
Deferred Investment Tax Credits	(3,363)	(1,408)	(174)	(400)	(67)
Total	(3,536)	(2,611)	6,789	5,984	1,904
Total Income Tax as Reported	$(1,955)	$110,926	$111,003	$44,837	$10,862

Year Ended December 31, 2002	OPCo	PSO	SWEPCo	TCC	TNC
			(in thousands)		
Charged (Credited) to Operating Expenses (net):					
Current	$86,026	$(49,673)	$41,354	$30,494	$109
Deferred	30,048	75,659	(3,134)	113,726	(10,652)
Deferred Investment Tax Credits	(2,493)	(1,791)	(4,524)	(5,206)	(1,271)
Total	113,581	24,195	33,696	139,014	(11,814)
Charged (Credited) to Nonoperating Income (net):					
Current	2,732	(1,812)	1,772	3,223	1,334
Deferred	15,962	-	-	(71)	(1,623)
Deferred Investment Tax Credits	(684)	-	-	-	-
Total	18,010	(1,812)	1,772	3,152	(289)
Total Income Tax as Reported	$131,591	$22,383	$35,468	$142,166	$(12,103)

Year Ended December 31, 2001	AEGCo	APCo	CSPCo	I&M	KPCo
			(in thousands)		
Charged (Credited) to Operating Expenses (net):					
Current	$9,126	$71,623	$88,013	$107,286	$7,726
Deferred	(6,224)	27,198	14,923	(45,785)	2,812
Deferred Investment Tax Credits	-	(3,237)	(3,899)	(7,377)	(1,180)
Total	2,902	95,584	99,037	54,124	9,358
Charged (Credited) to Nonoperating Income (net):					
Current	(56)	(19,165)	(13,803)	(10,590)	(2,726)
Deferred	-	21,832	17,885	16,580	3,481
Deferred Investment Tax Credits	(3,414)	(1,528)	(159)	(947)	(71)
Total	(3,470)	1,139	3,923	5,043	684
Total Income Tax as Reported	$(568)	$96,723	$102,960	$59,167	$10,042

Year Ended December 31, 2001	OPCo	PSO	SWEPCo	TCC	TNC
			(in thousands)		
Charged (Credited) to Operating Expenses (net):					
Current	$(62,298)	$53,030	$77,965	$190,672	$19,424
Deferred	166,166	(16,726)	(31,396)	(72,568)	(11,891)
Deferred Investment Tax Credits	(2,495)	(1,791)	(4,453)	(5,208)	(1,271)
Total	101,373	34,513	42,116	112,896	6,262
Charged (Credited) to Nonoperating Income (net):					
Current	(21,600)	352	542	(1,749)	(691)
Deferred	20,014	-	-	-	-
Deferred Investment Tax Credits	(794)	-	-	-	-
Total	(2,380)	352	542	(1,749)	(691)
Total Income Tax as Reported	$98,993	$34,865	$42,658	$111,147	$5,571

Shown below is a reconciliation for each registrant subsidiary of the difference between the amount of federal income taxes computed by multiplying book income before federal income taxes by the statutory rate, and the amount of income taxes reported.

	AEGCo	APCo	CSPCo	I&M	KPCo
Year Ended December 31, 2003			(in thousands)		
Net Income	$7,964	$280,040	$200,430	$86,388	$32,330
Cumulative Effect of Accounting Change	-	(77,257)	(27,283)	3,160	1,134
Income Taxes	(1,907)	105,220	73,662	41,148	9,675
Pre-Tax Income	$6,057	$308,003	$246,809	$130,696	$43,139
Income Tax on Pre-Tax Income at Statutory Rate *(35%)*	$2,120	$107,801	$86,383	$45,744	$15,099
Increase (Decrease) in Income Tax Resulting from the Following Items:					
Depreciation	371	9,263	2,220	19,288	1,538
Nuclear Fuel Disposal Costs	-	-	-	(6,465)	-
Allowance for Funds Used During Construction	(1,053)	(2,048)	(232)	(4,127)	(851)
Rockport Plant Unit 2 Investment Tax Credit	374	-	-	397	-
Removal Costs	-	(2,280)	(7)	(693)	(735)
Investment Tax Credits (net)	(3,354)	(3,146)	(3,110)	(7,431)	(1,210)
State Income Taxes	372	1,123	(3,074)	4,634	(58)
Other	(737)	(5,493)	(8,518)	(10,199)	(4,108)
Total Income Taxes as Reported	$(1,907)	$105,220	$73,662	$41,148	$9,675
Effective Income Tax Rate	N.M.	34.2%	29.8%	31.5%	22.4%

	OPCo	PSO	SWEPCo	TCC	TNC
Year Ended December 31, 2003			(in thousands)		
Net Income	$375,663	$53,891	$98,141	$217,669	$58,557
Cumulative Effect of Accounting Change	(124,632)	-	(8,517)	(122)	(3,071)
Extraordinary Loss	-	-	-	-	177
Income Taxes	138,399	37,837	51,072	105,172	30,263
Pre-Tax Income	$389,430	$91,728	$140,696	$322,719	$85,926
Income Tax on Pre-Tax Income at Statutory Rate *(35%)*	$136,301	$32,105	$49,244	$112,952	$30,074
Increase (Decrease) in Income Tax Resulting from the Following Items:					
Depreciation	4,388	1,166	834	486	286
Investment Tax Credits (net)	(3,107)	(1,791)	(4,326)	(5,207)	(1,521)
State Income Taxes	4,717	2,886	9,723	(10,434)	3,078
Other	(3,900)	3,471	(4,403)	7,375	(1,654)
Total Income Taxes as Reported	$138,399	$37,837	$51,072	$105,172	$30,263
Effective Income Tax Rate	35.5%	41.2%	36.3%	32.6%	35.2%

Year Ended December 31, 2002	AEGCo	APCo	CSPCo	I&M	KPCo
			(in thousands)		
Net Income	$7,552	$205,492	$181,173	$73,992	$20,567
Income Taxes	(1,955)	110,926	111,003	44,837	10,862
Pre-Tax Income	$5,597	$316,418	$292,176	$118,829	$31,429
Income Tax on Pre-Tax Income at Statutory Rate *(35%)*	$1,959	$110,746	$102,262	$41,590	$11,000
Increase (Decrease) in Income Tax Resulting from the Following Items:					
Depreciation	286	3,082	2,899	21,812	2,057
Nuclear Fuel Disposal Costs	-	-	-	(3,087)	-
Allowance for Funds Used During Construction	(1,136)	-	-	(3,453)	-
Rockport Plant Unit 2 Investment Tax Credit	374	-	-	-	-
Removal Costs	-	-	-	-	(735)
Investment Tax Credits (net)	(3,361)	(4,637)	(3,270)	(7,740)	(1,240)
State Income Taxes	335	6,469	11,387	124	1,058
Other	(412)	(4,734)	(2,275)	(4,409)	(1,278)
Total Income Taxes as Reported	$(1,955)	$110,926	$111,003	$44,837	$10,862
Effective Income Tax Rate	N.M.	35.1%	38.0%	37.7%	34.6%

Year Ended December 31, 2002	OPCo	PSO	SWEPCo	TCC	TNC
			(in thousands)		
Net Income (Loss)	$220,023	$41,060	$82,992	$275,941	$(13,677)
Income Taxes	131,591	22,383	35,468	142,166	(12,103)
Pre-Tax Income (Loss)	$351,614	$63,443	$118,460	$418,107	$(25,780)
Income Tax on Pre-Tax Income (Loss) at Statutory Rate *(35%)*	$123,065	$22,205	$41,461	$146,337	$(9,023)
Increase (Decrease) in Income Tax Resulting from the Following Items:					
Depreciation	4,227	(583)	(2,790)	(295)	(32)
Investment Tax Credits (net)	(3,177)	(1,791)	(4,524)	(5,207)	(1,271)
State Income Taxes	18,051	2,639	3,987	2,202	(1,577)
Other	(10,575)	(87)	(2,666)	(871)	(200)
Total Income Taxes as Reported	$131,591	$22,383	$35,468	$142,166	$(12,103)
Effective Income Tax Rate	37.4%	35.3%	29.9%	34.0%	46.9%

Year Ended December 31, 2001	AEGCo	APCo	CSPCo	I&M	KPCo
			(in thousands)		
Net Income	$7,875	$161,818	$161,876	$75,788	$21,565
Extraordinary Loss	-	-	30,024	-	-
Income Taxes	(568)	96,723	102,960	59,167	10,042
Pre-Tax Income	$7,307	$258,541	$294,860	$134,955	$31,607
Income Tax on Pre-Tax Income at Statutory Rate *(35%)*	$2,557	$90,489	$103,201	$47,234	$11,062
Increase (Decrease) in Income Tax Resulting from the Following Items:					
Depreciation	230	2,977	2,757	21,224	1,581
Nuclear Fuel Disposal Costs	-	-	-	(3,292)	-
Allowance for Funds Used During Construction	(1,078)	-	-	(1,606)	-
Rockport Plant Unit 2 Investment Tax Credit	374	-	-	-	-
Removal Costs	-	-	-	-	(420)
Investment Tax Credits (net)	(3,414)	(4,765)	(4,058)	(8,324)	(1,252)
State Income Taxes	1,050	9,613	5,727	6,137	318
Other	(287)	(1,591)	(4,667)	(2,206)	(1,247)
Total Income Taxes as Reported	$(568)	$96,723	$102,960	$59,167	$10,042
Effective Income Tax Rate	N.M.	37.4%	34.9%	43.8%	31.8%

Year Ended December 31, 2001	OPCo	PSO	SWEPCo	TCC	TNC
			(in thousands)		
Net Income	$147,445	$57,759	$89,367	$182,278	$12,310
Extraordinary Loss	18,348	-	-	-	-
Income Taxes	98,993	34,865	42,658	111,147	5,571
Pre-Tax Income	$264,786	$92,624	$132,025	$293,425	$17,881
Income Tax on Pre-Tax Income at Statutory Rate *(35%)*	$92,675	$32,418	$46,209	$102,699	$6,258
Increase (Decrease) in Income Tax Resulting from the Following Items:					
Depreciation	7,972	1,127	(501)	8,477	1,463
Investment Tax Credits (net)	(3,289)	(1,791)	(4,453)	(5,207)	(1,271)
State Income Taxes	9,752	5,137	5,451	9,652	1,283
Other	(8,117)	(2,026)	(4,048)	(4,474)	(2,162)
Total Income Taxes as Reported	$98,993	$34,865	$42,658	$111,147	$5,571
Effective Income Tax Rate	37.4%	37.6%	32.3%	37.9%	31.2%

The following tables show the elements of the net deferred tax liability and the significant temporary differences for each registrant subsidiary:

December 31, 2003	AEGCo	APCo	CSPCo	I&M	KPCo
			(in thousands)		
Deferred Tax Assets	$79,545	$237,873	$122,453	$695,037	$44,413
Deferred Tax Liabilities	(103,874)	(1,041,228)	(580,951)	(1,032,413)	(256,534)
Net Deferred Tax Liabilities	$(24,329)	$(803,355)	$(458,498)	$(337,376)	$(212,121)
Property Related Temporary Differences	$(62,271)	$(623,126)	$(357,980)	$(74,501)	$(151,404)
Amounts Due From Customers For Future Federal Income Taxes	6,949	(94,457)	(5,575)	(37,233)	(23,203)
Deferred State Income Taxes	(4,350)	(87,484)	(26,972)	(45,736)	(33,535)
Transition Regulatory Assets	-	(10,799)	(66,002)	-	-
Deferred Income Taxes on Other Comprehensive Loss	-	28,047	24,946	13,519	3,345
Net Deferred Gain on Sale and Leaseback-Rockport Plant Unit 2	36,916	-	-	24,563	-
Accrued Nuclear Decommissioning Expense	-	-	-	(173,054)	-
Deferred Fuel and Purchased Power	-	24,047	(273)	(19)	496
Deferred Cook Plant Restart Costs	-	-	-	(20,064)	-
Nuclear Fuel	-	-	-	(7,027)	-
All Other (Net)	(1,573)	(39,583)	(26,642)	(17,824)	(7,820)
Net Deferred Tax Liabilities	$(24,329)	$(803,355)	$(458,498)	$(337,376)	$(212,121)

December 31, 2003	OPCo	PSO	SWEPCo	TCC	TNC
			(in thousands)		
Deferred Tax Assets	$192,026	$164,801	$163,457	$298,648	$67,794
Deferred Tax Liabilities	(1,125,608)	(500,235)	(512,521)	(1,543,560)	(180,813)
Net Deferred Tax Liabilities	$(933,582)	$(335,434)	$(349,064)	$(1,244,912)	$(113,019)
Property Related Temporary Differences	$(721,118)	$(297,809)	$(307,023)	$(698,554)	$(118,876)
Amounts Due From Customers For Future Federal Income Taxes	(55,143)	8,728	(5,800)	(191,615)	9,979
Deferred State Income Taxes	(80,573)	(56,413)	(33,651)	(42,044)	(2,946)
Transition Regulatory Assets	(109,150)	-	-	(68,076)	-
Accrued Nuclear Decommissioning Expense	-	-	-	(1,470)	-
Nuclear Fuel	-	-	-	(7,240)	-
Deferred Income Taxes on Other Comprehensive Loss	26,280	23,607	23,644	33,316	14,387
Deferred Fuel and Purchased Power	12	(8,460)	(10,996)	(1,738)	(10,143)
Regulatory Assets Designated for Securitization	-	-	-	(281,260)	-
All Other (Net)	6,110	(5,087)	(15,238)	13,769	(5,420)
Net Deferred Tax Liabilities	$(933,582)	$(335,434)	$(349,064)	$(1,244,912)	$(113,019)

December 31, 2002	AEGCo	APCo	CSPCo	I&M	KPCo
		(in thousands)			
Deferred Tax Assets	$82,889	$247,080	$106,597	$436,361	$45,231
Deferred Tax Liabilities	(111,891)	(948,881)	(544,368)	(792,558)	(223,544)
Net Deferred Tax Liabilities	$(29,002)	$(701,801)	$(437,771)	$(356,197)	$(178,313)
Property Related Temporary Differences	$(74,291)	$(555,806)	$(331,166)	$(343,362)	$(127,069)
Amounts Due From Customers For Future Federal Income Taxes	7,626	(58,246)	(8,895)	(38,752)	(20,488)
Deferred State Income Taxes	(5,119)	(77,693)	(23,448)	(52,528)	(28,722)
Transition Regulatory Assets	-	(28,735)	(71,752)	-	-
Deferred Income Taxes on Other Comprehensive Loss	-	38,823	31,961	21,800	5,089
Net Deferred Gain on Sale and Leaseback-Rockport Plant Unit 2	38,866	-	-	25,860	-
Accrued Nuclear Decommissioning Expense	-	-	-	65,856	-
Deferred Fuel and Purchased Power	-	(1,878)	(273)	(13,144)	415
Deferred Cook Plant Restart Costs	-	-	-	(14,000)	-
Nuclear Fuel	-	-	-	(5,153)	-
All Other (Net)	3,916	(18,266)	(34,198)	(2,774)	(7,538)
Net Deferred Tax Liabilities	$(29,002)	$(701,801)	$(437,771)	$(356,197)	$(178,313)

December 31, 2002	OPCo	PSO	SWEPCo	TCC	TNC
		(in thousands)			
Deferred Tax Assets	$189,281	$141,571	$158,925	$164,343	$62,211
Deferred Tax Liabilities	(983,668)	(482,967)	(499,989)	(1,425,595)	(179,732)
Net Deferred Tax Liabilities	$(794,387)	$(341,396)	$(341,064)	$(1,261,252)	$(117,521)
Property Related Temporary Differences	$(620,019)	$(303,888)	$(315,821)	$(709,246)	$(127,038)
Amounts Due From Customers For Future Federal Income Taxes	(53,256)	9,490	(4,078)	(198,595)	5,726
Deferred State Income Taxes	(46,990)	(57,911)	(48,372)	(66,333)	(4,080)
Transition Regulatory Assets	(131,833)	-	-	-	-
Accrued Nuclear Decommissioning Expense	-	-	-	(1,117)	-
Nuclear Fuel	-	-	-	(7,023)	-
Deferred Income Taxes on Other Comprehensive Loss	39,246	29,332	28,906	39,394	16,565
Deferred Fuel and Purchased Power	540	(28,696)	3,192	2,655	(9,933)
Regulatory Assets Designated For Securitization	-	-	-	(310,410)	-
All Other (Net)	17,925	10,277	(4,891)	(10,577)	1,239
Net Deferred Tax Liabilities	$(794,387)	$(341,396)	$(341,064)	$(1,261,252)	$(117,521)

Registrant subsidiaries have settled with the IRS all issues from the audits of our consolidated federal income tax returns for the years prior to 1991. Registrant Subsidiaries have received Revenue Agent's Reports from the IRS for the years 1991 through 1996, and have filed protests contesting certain proposed adjustments. Returns for the years 1997 through 2000 are presently being audited by the IRS. Management is not aware of any issues for open tax years that upon final resolution are expected to have a material adverse effect on results of operations.

Registrant Subsidiaries join in the filing of a consolidated federal income tax return with the AEP System. The allocation of the AEP System's current consolidated federal income tax to the System companies is in accordance with SEC rules under the 1935 Act. These rules permit the allocation of the benefit of current tax losses to the System companies giving rise to them in determining their current tax expense. The tax loss of the System parent company, AEP Co., Inc., is allocated to its subsidiaries with taxable income. With the exception of the loss of the

parent company, the method of allocation approximates a separate return result for each company in the consolidated group.

15. LEASES

Leases of property, plant and equipment are for periods up to 99 years and require payments of related property taxes, maintenance and operating costs. The majority of the leases have purchase or renewal options and will be renewed or replaced by other leases.

Lease rentals for both operating and capital leases are generally charged to operating expenses in accordance with rate-making treatment for regulated operations. Capital leases for non-regulated property are accounted for as if the assets were owned and financed. The components of rental costs are as follows:

	AEGCo	APCo	CSPCo	I&M	KPCo	OPCo
Year Ended December 31, 2003			(in thousands)			
Lease Payments on Operating Leases	$76,322	$6,148	$5,277	$110,714	$1,258	$27,337
Amortization of Capital Leases	269	9,217	4,898	7,370	1,951	9,437
Interest on Capital Leases	-	1,123	899	1,276	148	2,472
Total Lease Rental Costs	$76,591	$16,488	$11,074	$119,360	$3,357	$39,246

	PSO	SWEPCo	TCC	TNC
Year Ended December 31, 2003		(in thousands)		
Lease Payments on Operating Leases	$4,883	$4,708	$6,360	$2,132
Amortization of Capital Leases	174	1,434	161	83
Interest on Capital Leases	17	899	16	9
Total Lease Rental Costs	$5,074	$7,041	$6,537	$2,224

	AEGCo	APCo	CSPCo	I&M	KPCo	OPCo
Year Ended December 31, 2002			(in thousands)			
Lease Payments on Operating Leases	$76,143	$6,634	$5,209	$110,833	$1,597	$68,816
Amortization of Capital Leases	238	9,729	6,010	8,319	2,171	12,637
Interest on Capital Leases	19	2,240	1,717	2,221	469	4,501
Total Lease Rental Costs	$76,400	$18,603	$12,936	$121,373	$4,237	$85,954

	PSO	SWEPCo	TCC	TNC
Year Ended December 31, 2002		(in thousands)		
Lease Payments on Operating Leases	$4,403	$3,240	$7,184	$1,981
Amortization of Capital Leases	-	-	-	-
Interest on Capital Leases	-	-	-	-
Total Lease Rental Costs	$4,403	$3,240	$7,184	$1,981

	AEGCo	APCo	CSPCo	I&M	KPCo	OPCo
Year Ended December 31, 2001			(in thousands)			
Lease Payments on Operating Leases	$76,262	$6,142	$7,063	$104,574	$1,191	$63,913
Amortization of Capital Leases	281	12,099	7,206	17,933	2,740	14,443
Interest on Capital Leases	55	3,789	2,396	4,424	808	5,818
Total Lease Rental Costs	$76,598	$22,030	$16,665	$126,931	$4,739	$84,174

Year Ended December 31, 2001	PSO	SWEPCo	TCC	TNC
		(in thousands)		
Lease Payments on Operating Leases	$4,010	$2,277	$5,948	$1,534
Amortization of Capital Leases	-	-	-	-
Interest on Capital Leases	-	-	-	-
Total Lease Rental Costs	$4,010	$2,277	$5,948	$1,534

Property, plant and equipment under capital leases and related obligations recorded on the Consolidated Balance Sheets are as follows:

Year Ended December 31, 2003	AEGCo	APCo	CSPCo	I&M	KPCo
		(in thousands)			
Property, Plant and Equipment Under Capital Leases					
Production	$865	$2,758	$7,104	$4,492	$1,138
Distribution	-	-	-	14,589	-
Other	-	55,640	25,345	52,536	11,562
Total Property, Plant and Equipment	865	58,398	32,449	71,617	12,700
Accumulated Amortization	596	33,036	16,828	33,774	7,408
Net Property, Plant and Equipment Under Capital Leases	$269	$25,362	$15,621	$37,843	$5,292
Obligations Under Capital Leases:					
Noncurrent Liability	$182	$16,134	$11,397	$31,315	$3,549
Liability Due Within One Year	87	9,218	4,221	6,528	1,743
Total Obligations Under Capital Leases	$269	$25,352	$15,618	$37,843	$5,292

Year Ended December 31, 2003	OPCo	PSO	SWEPCo	TCC	TNC
			(in thousands)		
Property, Plant and Equipment Under Capital Leases					
Production	$21,099	$-	$-	$-	$-
Distribution	-	-	-	-	-
Other	53,752	1,176	52,695	1,204	556
Total Property, Plant and Equipment	74,851	1,176	52,695	1,204	556
Accumulated Amortization	40,565	166	31,153	160	83
Net Property, Plant and Equipment Under Capital Leases	$34,286	$1,010	$21,542	$1,044	$473
Obligations Under Capital Leases:					
Noncurrent Liability	$25,064	$558	$18,383	$636	$270
Liability Due Within One Year	9,624	452	3,159	407	203
Total Obligations Under Capital Leases	$34,688	$1,010	$21,542	$1,043	$473

Year Ended December 31, 2002	AEGCo	APCo	CSPCo	I&M	KPCo
		(in thousands)			
Property, Plant and Equipment Under Capital Leases					
Production	$1,793	$3,368	$6,380	$5,728	$1,138
Distribution	-	-	-	14,589	-
Other:					
Mining Assets and Other	-	67,395	46,791	70,140	14,258
Total Property, Plant and Equipment	1,793	70,763	53,171	90,457	15,396
Accumulated Amortization	1,294	37,452	26,551	41,141	8,168
Net Property, Plant and Equipment Under Capital Leases	$499	$33,311	$26,620	$49,316	$7,228
Obligations Under Capital Leases:					
Noncurrent Liability	$301	$23,991	$21,643	$42,619	$5,093
Liability Due Within One Year	200	9,598	5,967	8,229	2,155
Total Obligations Under Capital Leases	$501	$33,589	$27,610	$50,848	$7,248

Year Ended December 31, 2002	OPCo	SWEPCo
	(in thousands)	
Property, Plant and Equipment Under Capital Leases		
Production	$21,360	$-
Distribution	-	-
Other:		
Mining Assets and Other	103,018	45,699
Total Property, Plant and Equipment	124,378	45,699
Accumulated Amortization	63,810	45,699
Net Property, Plant and Equipment Under Capital Leases	$60,568	$-
Obligations Under Capital Leases:		
Noncurrent Liability	$51,266	$-
Liability Due Within One Year	14,360	-
Total Obligations Under Capital Leases	$65,626	$-

Future minimum lease payments consisted of the following at December 31, 2003:

	APCo	CSPCo	I&M	KPCo	OPCo
			(in thousands)		
Capital Leases					
2004	$11,735	$4,959	$10,050	$2,107	$11,046
2005	6,853	4,025	7,478	1,640	8,093
2006	5,183	2,676	6,239	957	7,536
2007	2,664	1,773	12,616	785	5,582
2008	2,645	2,050	3,669	256	3,677
Later Years	1,802	2,096	5,994	116	4,627
Total Future Minimum Lease Payments	30,882	17,579	46,046	5,861	40,561
Less Estimated Interest Element	5,530	1,961	8,203	569	5,874
Estimated Present Value of Future Minimum Lease Payments	$25,352	$15,618	$37,843	$5,292	$34,687

	PSO	SWEPCo	TCC	TNC
		(in thousands)		
Capital Leases				
2004	$492	$4,737	$450	$223
2005	368	4,641	373	188
2006	194	4,533	198	87
2007	46	4,410	86	8
2008	4	4,389	24	1
Later Years	-	4,380	-	2
Total Future Minimum Lease Payments	1,104	27,090	1,131	509
Less Estimated Interest Element	94	5,548	88	36
Estimated Present Value of Future Minimum Lease Payments	$1,010	$21,542	$1,043	$473

	AEGCo	APCo	CSPCo	I&M	KPCo	OPCo
			(in thousands)			
Noncancellable Operating Leases						
2004	$73,854	$5,998	$5,078	$103,909	$1,209	$12,655
2005	73,854	5,154	4,920	97,447	1,084	11,886
2006	73,854	4,455	2,518	93,993	793	11,576
2007	73,854	3,302	2,205	91,328	771	11,132
2008	73,854	2,394	1,609	90,749	475	10,787
Later Years	1,033,956	6,094	2,726	1,096,567	1,785	66,918
Total Future Minimum Lease Payments	$1,403,226	$27,397	$19,056	$1,573,993	$6,117	$124,954

	PSO	SWEPCo	TCC	TNC
		(in thousands)		
Noncancellable Operating Leases				
2004	$4,684	$5,522	$6,112	$1,964
2005	4,520	6,020	5,886	1,945
2006	4,079	6,844	5,218	1,846
2007	3,424	7,218	4,397	1,532
2008	1,218	7,451	3,950	1,238
Later Years	8,616	17,849	11,272	4,981
Total Future Minimum Lease Payments	$26,541	$50,904	$36,835	$13,506

Gavin Lease

OPCo has entered into an agreement with JMG, an unrelated special purpose entity. JMG has a capital structure of which 3% is equity from investors with no relationship to AEP or any of its subsidiaries and 97% is debt from commercial paper, pollution control bonds and other bonds. JMG was formed to design, construct and lease the Gavin Scrubber for the Gavin Plant to OPCo. JMG owns the Gavin Scrubber and leases it to OPCo. Prior to July 1, 2003, the lease was accounted for as an operating lease. Payments under the lease agreement are based on JMG's cost of financing (both debt and equity) and include an amortization component plus the cost of administration. OPCo and AEP do not have an ownership interest in JMG and do not guarantee JMG's debt.

At any time during the lease, OPCo has the option to purchase the Gavin Scrubber for the greater of its fair market value or adjusted acquisition cost (equal to the unamortized debt and equity of JMG) or sell the Gavin Scrubber on behalf of JMG. The initial 15-year lease term is non-cancelable. At the end of the initial term, OPCo can renew the lease, purchase the Gavin Scrubber (terms previously mentioned), or sell the Gavin Scrubber on behalf of JMG. In case of a sale at less than the adjusted acquisition cost, OPCo must pay the difference to JMG.

On March 31, 2003, OPCo made a prepayment of $90 million under this lease structure. AEP recognizes lease expense on a straight-line basis over the remaining lease term, in accordance with SFAS 13 "Accounting for Leases." The asset will be amortized over the remaining lease term, which ends in the first quarter of 2010.

On July 1, 2003, OPCo consolidated JMG due to the application of FIN 46. Upon consolidation, OPCo recorded the assets and liabilities of JMG ($469.6 million). OPCo now records the depreciation, interest and other operating expenses of JMG and eliminates JMG's revenues against OPCo's operating lease expenses. There was no cumulative effect of an accounting change recorded as a result of AEP's requirement to consolidate JMG, and there was no change in net income due to the consolidation of JMG. Since the debt obligations of JMG are now consolidated, the JMG lease is no longer accounted for on a consolidated basis as an operating lease and has been excluded from the above table of future minimum lease payments.

Rockport Lease

AEGCo and I&M entered into a sale and leaseback transaction in 1989 with Wilmington Trust Company (Owner Trustee) an unrelated unconsolidated trustee for Rockport Plant Unit 2 (the plant). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and securities in a private placement to certain institutional investors. The future minimum lease payments for each respective company are $1.4 billion.

The FASB and other accounting constituencies continue to interpret the application of FIN 46 (revised December 2003) (FIN 46R). As a result, AEGCo and I&M are continuing to review the application of this new interpretation as it relates to the Rockport Plant Unit 2 transaction.
The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the plant and leases it to AEGCo and I&M. The lease is accounted for as an operating lease with the payment obligations included in the future minimum lease payments schedule earlier in this note. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the plant. Neither AEGCo, I&M nor AEP has an ownership interest in the Owner Trustee and do not guarantee its debt.

16. FINANCING ACTIVITIES

Trust Preferred Securities

PSO, SWEPCo and TCC have wholly-owned business trusts that have issued trust preferred securities. The trusts which hold mandatorily redeemable trust preferred securities were deconsolidated effective July 1, 2003 due to the implementation of FIN 46. Therefore, $321 million ($75 million PSO, $110 million SWEPCo and $136 million TCC), previously reported at December 31, 2002 as Certain Subsidiary Obligated, Mandatorily Redeemable, Preferred Securities of Subsidiary Trusts Holding Solely Junior Subordinated Debentures of Such Subsidiaries, is now reported as two components on the Balance Sheet. The investment in the trust is now reported as Other Investments within Other Property and Investments of $10 million ($2 million PSO, $3 million SWEPCo and $5 million TCC) and the subordinated debentures are now reported as Notes Payable to Trust within Long-term Debt of $331 million ($77 million PSO, $113 million SWEPCo and $141 million TCC).

The Junior Subordinated Debentures of PSO and TCC mature on April 30, 2037. In October 2003, SWEPCo refinanced its Junior Subordinated Debentures which are now due October 1, 2043. The following Trust Preferred Securities issued by the wholly-owned statutory business trusts of PSO, SWEPCo and TCC were outstanding at December 31, 2003 and 2002:

Business Trust	Security	Units Issued/ Outstanding at 12/31/03	Amount in Other Investments at 12/31/03 (a) (in millions)	Amount in Notes Payable to Trust at 12/31/03 (b) (in millions)	Amount Reported Prior to FIN 46 at 12/31/02 (c) (in millions)	Description of Underlying Debentures of Registrant
CPL Capital I	8.00%, Series A	5,450,000	$5	$141	$136	TCC, $141 million, 8.00%, Series A
PSO Capital I	8.00%, Series A	3,000,000	2	77	75	PSO, $77 million, 8.00%, Series A
SWEPCo Capital I	7.875%, Series A	-	-	-	110	SWEPCo, $113 million, 7.875%, Series A
SWEPCo Capital I	5.25%, Series B	110,000	3	113	-	SWEPCo, $113 million, 5.25% five year fixed rate period, Series B
		8,560,000	$10	$331	$321	

(a) Amounts are in Other Investments within Other Property and Investments.
(b) Amounts are in Notes Payable to Trust within Long-term Debt.
(c) Amounts reported on Balance Sheet prior to FIN 46.

Each of the business trusts is treated as a non-consolidated subsidiary of its parent company. The only assets of the business trusts are the subordinated debentures issued by their parent company as specified above. In addition to the obligations under their subordinated debentures, each of the parent companies has also agreed to a security obligation which represents a full and unconditional guarantee of its capital trust obligation.

Lines of Credit – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of its subsidiaries. The corporate borrowing program includes a utility money pool, which funds the utility subsidiaries, and a non-utility money pool, which funds the majority of the non-utility subsidiaries. In addition, the AEP System also funds, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in the non-utility money pool for regulatory or operational reasons. The AEP System Corporate Borrowing Program operates in accordance with the terms and conditions outlined by the SEC. AEP has authority from the SEC through March 31, 2006 for short-term borrowings sufficient to fund the utility money pool and the non-utility money pool as well as its own requirements in an amount not to exceed $7.2 billion. Utility money pool participants include AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC (domestic utility companies). The following are the SEC-authorized limits for short-term borrowings for the domestic utility companies as of December 31, 2003:

	Authorized (in millions)
AEP Generating Company	$125
AEP Texas Central Company (a)	438
AEP Texas North Company (a)	275
Appalachian Power Company	600
Columbus Southern Power Company (a)	150
Indiana Michigan Power Company	500
Kentucky Power Company	200
Ohio Power Company (a)	200
Public Service Company of Oklahoma	300
Southwestern Electric Power Company	350

(a) Short-term borrowing limits for these domestic utility companies are reduced by long-term debt issued commencing with the SEC order dated December 18, 2002, which authorized financing transactions through March 31, 2006.

As of December 31, 2003, AEP had credit facilities totaling $2.9 billion to support its commercial paper program. At December 31, 2003, AEP had $326 million outstanding in short-term borrowings of which $282 million was commercial paper supported by the revolving credit facilities. In addition, JMG has commercial paper outstanding in the amount of $26 million. This commercial paper is specifically associated with the Gavin scrubber lease identified in Note 15 "Leases". This commercial paper does not reduce available liquidity to AEP. The maximum amount of commercial paper outstanding during the year, which had a weighted average interest rate during 2003 of 1.98%, was $1.5 billion during January 2003. On December 11, 2002, Moody's Investor Services placed AEP's Prime-2 short-term rating for commercial paper under review for possible downgrade. On January 24, 2003, Standard & Poor's Rating Services placed AEP's A-2 short-term rating for commercial paper under review for possible downgrade. On February 10, 2003, Moody's Investor Services downgraded AEP's short-term rating for commercial paper to Prime-3 from Prime-2. On March 7, 2003, Standard & Poor's Rating Services reaffirmed AEP's A-2 short-term rating for commercial paper.

Net interest income (expense) recorded by each registrant subsidiary related to amounts advanced to (borrowed from) the AEP money pool were:

	Year Ended December 31,		
	2003	2002	2001
		(in millions)	
AEGCo	$(0.3)	$(0.2)	$(0.7)
APCo	1.4	(4.1)	(9.9)
CSPCo	-	(1.1)	(4.9)
I&M	1.5	1.0	(12.6)
KPCo	(0.9)	(1.6)	(2.3)
OPCo	(1.6)	(5.7)	(13.2)
PSO	(1.1)	(4.1)	(5.8)
SWEPCo	0.1	(2.8)	(2.3)
TCC	-	(6.3)	(11.1)
TNC	(0.3)	(3.2)	(3.0)

Outstanding short-term debt for AEP Consolidated consisted of:

	Year Ended December 31,	
	2003	2002
	(in millions)	
Balance Outstanding:		
Notes Payable	$18	$1,322
Commercial Paper – AEP	282	1,417
Commercial Paper – JMG	26	-
Total	$326	$2,739

Sale of Receivables – AEP Credit

AEP Credit has a sale of receivables agreement with banks and commercial paper conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires to the commercial paper conduits and banks and receives cash. This transaction constitutes a sale of receivables in accordance with SFAS 140, allowing the receivables to be taken off of AEP Credit's balance sheet and allowing AEP Credit to repay any debt obligations. AEP has no ownership interest in the commercial paper conduits and does not consolidate these entities in accordance with GAAP. We continue to service the receivables. This off-balance sheet transaction was entered into to allow AEP Credit to repay its outstanding debt obligations, continue to purchase the AEP operating companies' receivables, and accelerate its cash collections.

AEP Credit extended its sale of receivables agreement to July 25, 2003 from its May 28, 2003 expiration date. The agreement was then renewed for an additional 364 days and now expires on July 23, 2004. This new agreement

provides commitments of $600 million to purchase receivables from AEP Credit. At December 31, 2003, $385 million was outstanding. As collections from receivables sold occur and are remitted, the outstanding balance for sold receivables is reduced and as new receivables are sold, the outstanding balance of sold receivables increases. All of the receivables sold represented affiliate receivables. AEP Credit maintains a retained interest in the receivables sold and this interest is pledged as collateral for the collection of the receivables sold. The fair value of the retained interest is based on book value due to the short-term nature of the accounts receivable less an allowance for anticipated uncollectible accounts.

AEP Credit purchases accounts receivable through purchase agreements with certain registrant subsidiaries and, until the first quarter of 2002, with non-affiliated companies. These subsidiaries include CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in all of its regulatory jurisdictions, only a portion of APCo's accounts receivable are sold to AEP Credit. As a result of the restructuring of electric utilities in the State of Texas, the purchase agreement between AEP Credit and Reliant Energy, Incorporated was terminated as of January 25, 2002 and the purchase agreement between AEP Credit and Texas-New Mexico Power Company, the last remaining non-affiliated company, was terminated on February 7, 2002. In addition, the purchase agreements between AEP Credit and its Texas affiliates, AEP Texas Central Company (formerly Central Power and Light Company) and AEP Texas North Company (formerly West Texas Utilities Company) were terminated effective March 20, 2002.

Comparative accounts receivable information for AEP Credit:

	Year Ended December 31,	
	2003	2002
	(in millions)	
Proceeds from Sale of Accounts Receivable	$5,221	$5,513
Accounts Receivable Retained Interest Less Uncollectible Accounts and Amounts Pledged as Collateral	124	76
Deferred Revenue from Servicing Accounts Receivable	1	1
Loss on Sale of Accounts Receivable	7	4
Average Variable Discount Rate	1.33%	1.92%
Retained Interest if 10% Adverse Change in Uncollectible Accounts	122	74
Retained Interest if 20% Adverse Change in Uncollectible Accounts	121	72

Historical loss and delinquency amount for the AEP System's customer accounts receivable managed portfolio:

	Face Value Year Ended December 31,	
	2003	2002
	(in millions)	
Customer Accounts Receivable Retained	$1,155	$1,553
Accrued Unbilled Revenues Retained	596	551
Miscellaneous Accounts Receivable Retained	83	93
Allowance for Uncollectible Accounts Retained	(124)	(108)
Total Net Balance Sheet Accounts Receivable	1,710	2,089
Customer Accounts Receivable Securitized (Affiliate)	385	454
Total Accounts Receivable Managed	$2,095	$2,543
Net Uncollectible Accounts Written Off	$39	$48

Customer accounts receivable retained and securitized for the domestic electric operating companies are managed by AEP Credit. Miscellaneous accounts receivable have been fully retained and not securitized.

At December 31, 2003, delinquent customer accounts receivable for the electric utility affiliates that AEP Credit currently factors was $30 million.

Under the factoring arrangement, participating registrant subsidiaries sell, without recourse, certain of their customer accounts receivable and accrued unbilled revenue balances to AEP Credit and are charged a fee based on AEP Credit financing costs, uncollectible accounts experience for each company's receivables and administrative costs. The costs of factoring customer accounts receivable are reported as an operating expense. The amount of factored accounts receivable and accrued unbilled revenues for each registrant subsidiary was as follows:

	December 31,	
	2003	2002
	(in millions)	
APCo	$60.2	$67.6
CSPCo	100.2	114.3
I&M	93.0	103.7
KPCo	30.4	29.5
OPCo	99.3	109.8
PSO	99.6	83.7
SWEPCo	64.4	65.2

The fees paid by the registrant subsidiaries to AEP Credit for factoring customer accounts receivable were:

	Year Ended December 31,		
	2003	2002	2001
		(in millions)	
APCo	$3.4	$ 4.8	$ 5.2
CSPCo	9.8	15.8	15.2
I&M	6.1	7.4	8.5
KPCo	2.4	2.7	2.7
OPCo	8.7	11.4	12.8
PSO	5.8	7.2	9.6
SWEPCo	4.9	5.4	7.4
TCC	-	2.2	14.7
TNC	-	1.4	3.8

17. RELATED PARTY TRANSACTIONS

AEP System Power Pool

APCo, CSPCo, I&M, KPCo and OPCo are parties to the Interconnection Agreement, dated July 6, 1951, as amended (the Interconnection Agreement), defining how they share the costs and benefits associated with their generating plants. This sharing is based upon each company's "member-load-ratio," which is calculated monthly on the basis of each company's maximum peak demand in relation to the sum of the maximum peak demands of all five companies during the preceding 12 months. In addition, since 1995, APCo, CSPCo, I&M, KPCo and OPCo have been parties to the AEP System Interim Allowance Agreement which provides, among other things, for the transfer of SO2 Allowances associated with transactions under the Interconnection Agreement. As part of AEP's restructuring settlement agreement filed with FERC, under certain conditions CSPCo and OPCo would no longer be parties to the Interconnection Agreement and certain other modifications to its terms would also be made.

Power and Gas and risk management activities are conducted by the AEP Power Pool and shared among the parties under the System Integration Agreement. Risk management activities involve the purchase and sale of electricity and gas under physical forward contracts at fixed and variable prices and the risk management of electricity and to a lesser extent gas contracts including exchange traded futures and options and over-the-counter options and swaps. The majority of these transactions represent physical forward contracts in the AEP System's traditional marketing area and are typically settled by entering into offsetting contracts. In addition, the AEP Power Pool enters into transactions for the purchase and sale of electricity and gas options, futures and swaps, and for the forward purchase and sale of electricity outside of the AEP System's traditional marketing area.

AEP West Companies

PSO, SWEPCo, TCC, TNC operating companies of the west zone and AEPSC are parties to a Restated and Amended Operating Agreement originally dated as of January 1, 1997 (CSW Operating Agreement). The CSW Operating Agreement requires the AEP West operating companies to maintain specified annual planning reserve margins and requires the operating companies that have capacity in excess of the required margins to make such capacity available for sale to other operating companies as capacity commitments. The CSW Operating Agreement also delegates to AEPSC the authority to coordinate the acquisition, disposition, planning, design and construction of generating units and to supervise the operation and maintenance of a central control center. As part of AEP's restructuring settlement agreement filed with the FERC, under certain conditions TCC and TNC would no longer be parties to the CSW Operating Agreement.

AEP's System Integration Agreement provides for the integration and coordination of AEP's east and west zone operating subsidiaries, joint dispatch of generation within the AEP System, and the distribution, between the two operating zones, of costs and benefits associated with the System's generating plants. It is designed to function as an umbrella agreement in addition to the AEP Interconnection Agreement and the CSW Operating Agreement, each of which will continue to control the distribution of costs and benefits within each zone.

The following table shows the revenues derived from sales to the pools and direct sales to affiliates for years ended December 31, 2003, 2002 and 2001:

	APCo	CSPCo	I&M	KPCo	OPCo	AEGCo
Related Party Revenues			(in thousands)			
2003 Sales to East System Pool	$130,921	$59,113	$228,667	$32,827	$503,334	$-
Sales to West System Pool	27	9	17	6	21	-
Direct Sales To East Affiliates	60,638	-	-	-	50,764	232,955
Direct Sales To West Affiliates	27,951	16,428	17,674	6,425	21,759	-
Other	3,256	8,819	2,845	550	8,400	-
Total Revenues	$222,793	$84,369	$249,203	$39,808	$584,278	$232,955
2002 Sales to East System Pool	$106,651	$42,986	$197,525	$22,369	$397,248	$-
Sales to West System Pool	18,300	12,107	13,036	4,717	16,265	-
Direct Sales To East Affiliates	58,213	-	-	-	50,599	213,071
Direct Sales To West Affiliates	-	-	-	-	-	-
Other	3,313	2,109	3,577	878	1,090	-
Total Revenues	$186,477	$57,202	$214,138	$27,964	$465,202	$213,071
2001 Sales to East System Pool	$91,977	$44,185	$239,277	$34,735	$431,637	$-
Sales to West System Pool	24,892	13,971	15,596	6,117	19,797	-
Direct Sales To East Affiliates	54,777	-	-	-	55,450	227,338
Direct Sales To West Affiliates	(3,133)	(1,705)	(1,905)	(744)	(2,590)	-
Other	2,772	11,060	2,071	2,258	7,072	-
Total Revenues	$171,285	$67,511	$255,039	$42,366	$511,366	$227,338

Related Party Revenues		PSO	SWEPCo	TCC	TNC
			(in thousands)		
2003	Sales to East System Pool	$-	$-	$-	$-
	Sales to West System Pool	793	600	15,157	651
	Direct Sales To East Affiliates	1,159	706	677	6
	Direct Sales To West Affiliates	17,855	64,802	23,248	1,929
	Other	3,323	2,746	114,486	52,567
	Total Revenues	$23,130	$68,854	$153,568	$55,153
2002	Sales to East System Pool	$-	$-	$-	$-
	Sales to West System Pool	674	1,334	18,416	1,280
	Direct Sales To East Affiliates	611	270	366	(23)
	Direct Sales To West Affiliates	6,047	75,674	956,751	228,404
	Other	2,107	(4,979)	32,911	10,764
	Total Revenues	$9,439	$72,299	$1,008,444	$240,425
2001	Sales to East System Pool	$4	$-	$-	$-
	Sales to West System Pool	3,317	8,073	19,865	322
	Direct Sales To East Affiliates	2,833	3,238	3,697	1,228
	Direct Sales To West Affiliates	30,668	67,930	12,617	9,350
	Other	(51)	(4)	5,583	7,781
	Total Revenues	$36,771	$79,237	$41,762	$18,681

The following table shows the purchased power expense incurred from purchases from the pools and affiliates for the years ended December 31, 2003, 2002, and 2001:

Related Party Purchases		APCo	CSPCo	I&M	KPCo	OPCo
				(in thousands)		
2003	Purchases from East System Pool	$348,899	$335,916	$109,826	$71,259	$88,962
	Purchases from West System Pool	-	-	-	-	-
	Direct Purchases from East Affiliates	1,546	936	164,069	70,249	1,234
	Direct Purchases from West Affiliates	765	471	505	182	625
	Total Purchases	$351,210	$337,323	$274,400	$141,690	$90,821
2002	Purchases from East System Pool	$233,677	$309,999	$83,918	$68,846	$70,338
	Purchases from West System Pool	337	219	237	86	297
	Direct Purchases from East Affiliates	583	387	149,569	64,070	519
	Direct Purchases from West Affiliates	-	-	-	-	-
	Total Purchases	$234,597	$310,605	$233,724	$133,002	$71,154
2001	Purchases from East System Pool	$346,582	$292,034	$79,030	$61,816	$62,350
	Purchases from West System Pool	296	165	185	72	235
	Direct Purchases from East Affiliates	-	-	159,022	68,316	-
	Direct Purchases from West Affiliates	-	-	-	-	-
	Total Purchases	$346,878	$292,199	$238,237	$130,204	$62,585

Related Party Purchases		PSO	SWEPCo	TCC	TNC
			(in thousands)		
2003	Purchases from East System Pool	$639	$-	$-	$-
	Purchases from West System Pool	704	741	289	15,467
	Direct Purchases from East Affiliates	46,384	28,376	10,238	4,677
	Direct Purchases from West Affiliates	61,912	18,087	8,570	19,265
	Other	-	710	-	-
	Total Purchases	$109,639	$47,914	$19,097	$39,409
2002	Purchases from East System Pool	$343	$-	$-	$-
	Purchases from West System Pool	874	(456)	1,366	15,475
	Direct Purchases from East Affiliates	29,029	17,242	8,236	2,669
	Direct Purchases from West Affiliates	59,208	25,236	13,804	19,438
	Total Purchases	$89,454	$42,022	$23,406	$37,582
2001	Purchases from East System Pool	$1,327	$-	$-	$4
	Purchases from West System Pool	5,877	3,810	415	11,689
	Direct Purchases from East Affiliates	1,951	2,352	12,657	4,614
	Direct Purchases from West Affiliates	34,603	9,696	45,569	40,349
	Total Purchases	$43,758	$15,858	$58,641	$56,656

The above summarized related party revenues and expenses are reported in their entirety, without elimination, and are presented as operating revenues affiliated and purchased power affiliated on the statements of operations of each AEP Power Pool member. Since all of the above pool members are included in AEP's consolidated results, the above summarized related party transactions are eliminated in total in AEP's consolidated revenues and expenses.

AEP System Transmission Pool

APCo, CSPCo, I&M, KPCo and OPCo are parties to the Transmission Agreement, dated April 1, 1984, as amended (the Transmission Agreement), defining how they share the costs associated with their relative ownership of the extra-high-voltage transmission system (facilities rated 345 kV and above) and certain facilities operated at lower voltages (138 kV and above). Like the Interconnection Agreement, this sharing is based upon each company's "member-load-ratio."

The following table shows the net (credits) or charges allocated among the parties to the Transmission Agreement during the years ended December 31, 2003, 2002 and 2001:

	2003	2002	2001
		(in thousands)	
APCo	$-	$(13,400)	$(3,100)
CSPCo	38,200	42,200	40,200
I&M	(39,800)	(36,100)	(41,300)
KPCo	(5,600)	(5,400)	(4,600)
OPCo	7,200	12,700	8,800

PSO, SWEPCo, TCC, TNC and AEPSC are parties to a Transmission Coordination Agreement originally dated as of January 1, 1997 (TCA). The TCA established a coordinating committee, which is charged with the responsibility of overseeing the coordinated planning of the transmission facilities of the west zone operating subsidiaries, including the performance of transmission planning studies, the interaction of such subsidiaries with independent system operators (ISO) and other regional bodies interested in transmission planning and compliance with the terms of the Open Access Transmission Tariff (OATT) filed with the FERC and the rules of the FERC relating to such tariff.

Under the TCA, the west zone operating subsidiaries have delegated to AEPSC the responsibility of monitoring the reliability of their transmission systems and administering the OATT on their behalf. The TCA also provides for the allocation among the west zone operating subsidiaries of revenues collected for transmission and ancillary services provided under the OATT.

The following table shows the net (credits) or charges allocated among parties to the Transmission Agreement during the years ended December 31, 2003, 2002 and 2001:

	2003	2002	2001
		(in thousands)	
PSO	$4,200	$4,200	$4,000
SWEPCo	5,000	5,000	5,400
TCC	(3,600)	(3,600)	(3,900)
TNC	(5,600)	(5,600)	(5,500)

AEP's System Transmission Integration Agreement provides for the integration and coordination of the planning, operation and maintenance of the transmission facilities of AEP's east and west zone operating subsidiaries. Like the System Integration Agreement, the System Transmission Integration Agreement functions as an umbrella agreement in addition to the AEP Transmission Agreement and the Transmission Coordination Agreement. The System Transmission Integration Agreement contains two service schedules that govern:

- The allocation of transmission costs and revenues
- The allocation of third-party transmission costs and revenues and System dispatch costs

The Transmission Integration Agreement anticipates that additional service schedules may be added as circumstances warrant.

AEP Coal, Inc.

AEP Coal, Inc. and CSPCo are parties to a 2003 coal purchase agreement, dated October 15, 2002. The agreement provides for the sale of up to 960,000 tons of coal mined by AEP Coal to be delivered (at CSP's expense) to the Conesville Plant for a price ranging from $23.15 per ton to $26.15 per ton plus quality adjustments. In 2002, AEP Coal, Inc. and CSPCo were parties to a 2002 coal purchase agreement, dated February 1, 2002. The agreement provided for the sale of up to 785,000 tons of coal mined by AEP Coal to be delivered (at CSP's expense) to the Conesville Plant for a price ranging from $24.00 per ton to $27.00 per ton plus quality adjustments. During 2003 and 2002, AEP Coal derived revenues from sales to CSPCo of $23.9 million and $21 million, respectively.

AEP Coal, Inc. and CSPCo are parties to a 1998 coal transloading agreement, dated June 12, 1998. Pursuant to the agreement, AEP Coal transfers coal from railcars into trucks at AEP Coal's Muskie Transloading Facility and delivers the coal via trucks to CSPCo's Conesville Preparation Plant or CSPCo's Power Plant for a rate of $1.25 per ton and $1.03 per ton, respectively. During 2003 and 2002, AEP Coal derived revenues from sales to CSPCo of $3.4 million and $3.5 million, respectively.

AEP East Companies

Effective October 31, 2003, AEPES assigned to AEPSC, as agent for the AEP East operating companies, approximately $97 million (negative value) associated with its natural gas contracts with DETM. The assignment was executed in order to consolidate DETM positions within AEP. Concurrently, in order to ensure that there would be no financial impact to the operating companies as a result of the assignment, AEPES and AEPSC entered into agreements requiring AEPES to reimburse AEPSC for any related cash settlements and all income related to the assigned contracts. There is no impact to the AEP consolidated financial statements. The following table represents registrant subsidiary liabilities at December 31, 2003 in thousands:

APCo	$(32,287)
CSPCo	(18,185)
I&M	(19,932)
KPCo	(7,349)
OPCo	(24,055)
Total	$(101,808)

Unit Power Agreements and Other

A unit power agreement between AEGCo and I&M (the I&M Power Agreement) provides for the sale by AEGCo to I&M of all the power (and the energy associated therewith) available to AEGCo at the Rockport Plant unless it is sold to another utility. I&M is obligated, whether or not power is available from AEGCo, to pay as a demand charge for the right to receive such power (and as an energy charge for any associated energy taken by I&M) such amounts, as when added to amounts received by AEGCo from any other sources, will be at least sufficient to enable AEGCo to pay all its operating and other expenses, including a rate of return on the common equity of AEGCo as approved by FERC. The I&M Power Agreement will continue in effect until the expiration of the lease term of Unit 2 of the Rockport Plant unless extended in specified circumstances.

Pursuant to an assignment between I&M and KPCo, and a unit power agreement between KPCo and AEGCo, AEGCo sells KPCo 30% of the power (and the energy associated therewith) available to AEGCo from both units of the Rockport Plant. KPCo has agreed to pay to AEGCo in consideration for the right to receive such power the same amounts which I&M would have paid AEGCo under the terms of the I&M Power Agreement for such entitlement. The KPCo unit power agreement expires on December 31, 2004.

APCo and OPCo, jointly own two power plants. The costs of operating these facilities are apportioned between the owners based on ownership interests. Each company's share of these costs is included in the appropriate expense accounts on each company's consolidated statements of income. Each company's investment in these plants is included in electric utility plant on its consolidated balance sheets.

I&M provides barging and other transportation services to affiliates. I&M records revenues from barging services as nonoperating income. The affiliates record costs paid to I&M for barging services as fuel expense or operation expense. The amount of affiliated revenues and affiliated expenses were:

	Year Ended December 31,		
	2003	2002	2001
Company		(in millions)	
I&M – revenues	$31.9	$34.3	$30.2
AEGCo – expense	8.1	7.8	8.5
APCo – expense	12.3	12.8	11.5
KEPCo – expense	0.1	-	-
OPCo – expense	4.3	7.9	10.2
MEMCo – expense (Non-Utility subsidiary of AEP)	7.1	5.7	-
AEP Energy Services (Non-Utility subsidiary of AEP)	-	0.1	-

In conjunction with a 500 MW agreement between OPCo and National Power Cooperative, Inc (NPC), AEPES entered into a fuel management agreement with those two parties to manage and procure fuel needs for the plant, which is owned by NPC. The plant went into service in July 2002. Because APCo, CSPCo, I&M, KPCo and OPCo purchase 100% of the available generating capacity from the plant, they also share in paying fuel expense to AEPES. The related purchases from AEPES were as follows:

	Year Ended December 31,	
	2003	2002
	(in thousands)	
KPCo	$363	$150
I&M	1,000	418
CSPCo	936	387
OPCo	1,234	519
APCo	1,546	583
Total	$5,079	$2,057

There was no activity in 2001.

HPL purchases physical gas in the spot market, which in turn, is sold to certain operating companies at cost for their fuel requirements. The related sales are as follows:

	Year Ended December 31,	
	2003	2002
	(in thousands)	
TCC	$195,527	$157,346
TNC	44,197	64,385

There was no activity in 2001.

AEPSC provides certain managerial and professional services to AEP System companies. The costs of the services are billed to its affiliated companies by AEPSC on a direct-charge basis, whenever possible, and on reasonable bases of proration for shared services. The billings for services are made at cost and include no compensation for the use of equity capital, which is furnished to AEPSC by AEP Co., Inc. Billings from AEPSC are capitalized or expensed depending on the nature of the services rendered. AEPSC and its billings are subject to the regulation of the SEC under the PUHCA.

18. JOINTLY OWNED ELECTRIC UTILITY PLANT

CSPCo, PSO, SWEPCo, TCC and TNC have generating units that are jointly owned with affiliated and unaffiliated companies. Each of the participating companies is obligated to pay its share of the costs of any such jointly owned facilities in the same proportion as its ownership interest. Each AEP registrant subsidiary's proportionate share of the operating costs associated with such facilities is included in its statements of operations and the investments are reflected in its balance sheets under utility plant as follows:

		Company's Share December 31,			
		2003		2002	
	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Utility Plant in Service	Construction Work in Progress
		(in thousands)		(in thousands)	
CSPCo					
W.C. Beckjord Generating Station (Unit No. 6)	12.5	$15,455	$127	$15,487	$49
Conesville Generating Station (Unit No. 4)	43.5	82,115	722	81,960	279
J.M. Stuart Generating Station	26.0	204,820	50,326	197,276	44,865
Wm. H. Zimmer Generating Station	25.4	707,281	31,249	705,620	14,077
Transmission	(a)	62,061	742	61,187	2,281
Total		$1,071,732	$83,166	$1,061,530	$61,551
PSO					
Oklaunion Generating Station (Unit No. 1)	15.6	$85,064	$518	$83,562	$777
SWEPCo					
Dolet Hills Generating Station (Unit No. 1)	40.2	$236,116	$2,304	$235,366	$1,313
Flint Creek Generating Station (Unit No. 1)	50.0	93,309	737	91,567	1,052
Pirkey Generating Station (Unit No. 1)	85.9	454,303	3,125	451,136	2,197
Total		$783,728	$6,166	$778,069	$4,562
TCC (b)					
Oklaunion Generating Station (Unit No. 1)	7.8	$38,798	$252	$38,055	$369
South Texas Project Generation Station (Units No. 1 and 2)	25.2	2,386,579	934	2,364,359	43,887
Total		$2,425,377	$1,186	$2,402,414	$44,256
TNC					
Oklaunion Generating Station (Unit No. 1)	54.7	$285,314	$1,351	$277,946	$3,650

(a) Varying percentages of ownership.
(b) Included in Assets Held for Sale - Texas Generation Plants on TCC's Consolidated Balance Sheets.

The accumulated depreciation with respect to each AEP registrant subsidiary's share of jointly owned facilities is shown below:

	December 31,	
	2003	2002
	(in thousands)	
CSPCo	$435,249	$436,683
PSO	50,968	49,085
SWEPCo	465,871	450,057
TCC (a)	991,665	927,193
TNC	103,642	102,542

(a) Included in Assets Held for Sale - Texas Generation Plants on TCC's Consolidated Balance Sheets.

19. UNAUDITED QUARTERLY FINANCIAL INFORMATION

The unaudited quarterly financial information for each AEP registrant subsidiary follows:

Quarterly Periods Ended	AEGCo	APCo	CSPCo	I&M	KPCo
			(in thousands)		
March 31, 2003					
Operating Revenues	$60,428	$536,228	$359,205	$418,598	$112,094
Operating Income	1,851	112,684	55,151	58,990	19,834
Income Before Extraordinary Items and Cumulative Effect of Accounting Changes	1,796	79,153	38,359	30,687	11,021
Net Income	1,796	156,410	65,642	27,527	9,887
June 30, 2003					
Operating Revenues	$59,568	$444,751	$333,071	$376,906	$95,464
Operating Income	1,514	49,056	43,417	19,229	10,964
Income (Loss) Before Extraordinary Items and Cumulative Effect of Accounting Changes	1,768	14,636	29,331	(1,191)	4,095
Net Income (Loss)	1,768	14,636	29,331	(1,191)	4,095
September 30, 2003					
Operating Revenues	$59,008	$483,611	$397,655	$423,004	$103,693
Operating Income	1,809	67,134	71,193	56,242	13,097
Income Before Extraordinary Items and Cumulative Effect of Accounting Changes	2,021	45,715	62,825	37,116	6,501
Net Income	2,021	45,715	62,825	37,116	6,501
December 31, 2003					
Operating Revenues	$54,161	$492,768	$341,920	$377,088	$105,219
Operating Income	2,000	89,937	55,725	51,606	20,849
Income Before Extraordinary Items and Cumulative Effect of Accounting Changes	2,379	63,279	42,632	22,936	11,847
Net Income	2,379	63,279	42,632	22,936	11,847

Quarterly Periods Ended	OPCo	PSO	SWEPCo	TCC	TNC
		(in thousands)			
March 31, 2003					
Operating Revenues	$590,631	$242,662	$255,278	$428,358	$116,262
Operating Income	98,870	13,146	26,044	92,010	9,865
Income Before Extraordinary Items and Cumulative Effect of Accounting Changes	68,350	691	10,491	64,437	6,765
Net Income	192,982	691	19,008	64,559	9,836
June 30, 2003					
Operating Revenues	$539,386	$277,236	$281,306	$482,446	$136,806
Operating Income	79,831	28,715	35,588	96,603	23,243
Income Before Extraordinary Items and Cumulative Effect of Accounting Changes	56,277	17,927	20,590	63,587	17,922
Net Income	56,277	17,927	20,590	63,587	17,922
September 30, 2003					
Operating Revenues	$565,318	$358,575	$361,622	$485,129	$114,455
Operating Income	93,798	43,527	59,229	84,502	17,419
Income Before Extraordinary Items and Cumulative Effect of Accounting Changes	70,367	38,090	42,181	66,221	17,347
Net Income	70,367	38,090	42,181	66,221	17,347
December 31, 2003					
Operating Revenues	$549,318	$224,349	$248,636	$351,578	$98,423
Operating Income	87,168	7,475	29,275	48,425	17,500
Income (Loss) Before Extraordinary Items and Cumulative Effect of Accounting Changes	56,037	(2,817)	16,362	23,302	13,629
Net Income (Loss)	56,037	(2,817)	16,362	23,302	13,452

Quarterly Periods Ended	AEGCo	APCo	CSPCo	I&M	KPCo
		(in thousands)			
March 31, 2002					
Operating Revenues	$49,875	$462,605	$314,826	$352,235	$99,185
Operating Income	1,767	81,554	45,548	30,363	15,484
Income Before Extraordinary Items and Cumulative Effect of Accounting Changes	1,893	55,341	33,858	11,058	10,246
Net Income	1,893	55,341	33,858	11,058	10,246
June 30, 2002					
Operating Revenues	$53,356	$432,015	$343,813	$369,043	$92,164
Operating Income	1,504	65,224	58,040	19,865	9,550
Income Before Extraordinary Items and Cumulative Effect of Accounting Changes	1,718	46,608	51,721	7,494	5,246
Net Income	1,718	46,608	51,721	7,494	5,246
September 30, 2002					
Operating Revenues	$55,988	$464,409	$421,892	$414,414	$97,811
Operating Income	1,436	81,365	89,033	57,004	11,119
Income Before Extraordinary Items and Cumulative Effect of Accounting Changes	1,947	53,947	76,117	35,312	5,994
Net Income	1,947	53,947	76,117	35,312	5,994
December 31, 2002					
Operating Revenues	$54,062	$455,441	$319,629	$391,072	$89,523
Operating Income	1,422	73,920	27,158	43,957	6,044
Income (Loss) Before Extraordinary Items and Cumulative Effect of Accounting Changes	1,994	49,596	19,477	20,128	(919)
Net Income (Loss)	1,994	49,596	19,477	20,128	(919)

Quarterly Periods Ended	OPCo	PSO	SWEPCo	TCC	TNC
		(in thousands)			
March 31, 2002					
Operating Revenues	$520,652	$148,986	$222,259	$278,910	$103,626
Operating Income	83,716	8,410	22,469	55,445	11,145
Income (Loss) Before Extraordinary Items and Cumulative Effect of Accounting Changes	64,051	(1,648)	8,159	24,445	3,992
Net Income (Loss)	64,051	(1,648)	8,159	24,445	3,992
June 30, 2002					
Operating Revenues	$521,365	$158,330	$263,074	$360,391	$104,452
Operating Income	61,046	20,201	31,988	64,319	5,547
Income Before Extraordinary Items and Cumulative Effect of Accounting Changes	55,348	11,620	18,155	33,535	675
Net Income	55,348	11,620	18,155	33,535	675
September 30, 2002					
Operating Revenues	$557,574	$230,098	$362,423	$546,260	$152,667
Operating Income (Loss)	97,210	50,710	60,254	118,204	(308)
Income (Loss) Before Extraordinary Items and Cumulative Effect of Accounting Changes	80,258	41,002	45,794	93,383	(4,193)
Net Income (Loss)	80,258	41,002	45,794	93,383	(4,193)
December 31, 2002					
Operating Revenues	$513,534	$256,233	$236,964	$504,932	$89,995
Operating Income (Loss)	56,357	5,400	27,758	155,765	(8,513)
Income (Loss) Before Extraordinary Items and Cumulative Effect of Accounting Changes	20,366	(9,914)	10,884	124,578	(14,151)
Net Income (Loss)	20,366	(9,914)	10,884	124,578	(14,151)

For each of the AEP registrant subsidiaries, there were no significant, non-recurring events in the fourth quarter of 2003 or 2002.

20. SUBSEQUENT EVENTS (UNAUDITED)

After December 31, 2003 we entered into separate agreements to dispose of the following investments:

Investment	Sales Price (in millions)	Date of Agreement
Oklaunion Power Station (TCC's 7.8% ownership interest)	$42.8	January 30, 2004
STP (TCC's 25.2% ownership interest)	$332.6	February 27, 2004

We anticipate these sales to be completed during 2004 and that the impact on results of operations will not be significant.

REGISTRANTS' COMBINED MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is a combined presentation of certain components of the registrants' management's discussion and analysis. The information in this section completes the information necessary for management's discussion and analysis of financial condition and results of operations and is meant to be read with (i) Management's Financial Discussion and Analysis, (ii) financial statements, (iii) footnotes and (iv) the schedules of each individual registrant.

Source of Funding

Short-term funding for AEP's electric subsidiaries comes from AEP's commercial paper program and revolving credit facilities. Proceeds are loaned to the subsidiaries through intercompany notes. AEP and its subsidiaries also operate a money pool to minimize the AEP System's external short-term funding requirements and sell accounts receivable to provide liquidity for certain electric subsidiaries. The electric subsidiaries generally use short-term funding sources (the money pool or receivables sales) to provide for interim financing of capital expenditures that exceed internally generated funds and periodically reduce their outstanding short-term debt through issuances of long-term debt, sale-leaseback, leasing arrangements and additional capital contributions from their parent company.

Sale of Receivables Through AEP Credit

AEP Credit has a sale of receivables agreement with banks and commercial paper conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires to the commercial paper conduits and banks and receives cash. This transaction constitutes a sale of receivables in accordance with SFAS 140, allowing the receivables to be removed from of AEP Credit's balance sheet and allowing AEP Credit to repay any debt obligations. AEP has no ownership interest in the commercial paper conduits and does not consolidate these entities in accordance with GAAP. The electric subsidiaries continue to service the receivables. This off-balance sheet transaction was entered into to allow AEP Credit to repay its outstanding debt obligations, continue to purchase the AEP operating companies' receivables, and accelerate its cash collections.

AEP Credit extended its sale of receivables agreement to July 25, 2003 from its May 28, 2003 expiration date. The agreement was then renewed for an additional 364 days and now expires on July 23, 2004. This new agreement provides commitments of $600 million to purchase receivables from AEP Credit. At December 31, 2003, $385 million was outstanding. As collections from receivables sold occur and are remitted, the outstanding balance for sold receivables is reduced and as new receivables are sold, the outstanding balance of sold receivables increases. All of the receivables sold represented affiliate receivables. AEP Credit maintains a retained interest in the receivables sold and this interest is pledged as collateral for the collection of the receivables sold. The fair value of the retained interest is based on book value due to the short-term nature of the accounts receivable less an allowance for anticipated uncollectible accounts.

AEP Credit purchases accounts receivable through purchase agreements with certain registrant subsidiaries. These subsidiaries include CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in all of its regulatory jurisdictions, only a portion of APCo's accounts receivable are sold to AEP Credit. In addition, the purchase agreements between AEP Credit and TCC and TNC were terminated effective March 20, 2002.

Budgeted Construction Expenditures

Construction expenditures for certain registrant subsidiaries for the next three years are:

	Projected Construction Expenditures (in millions)	Construction Expenditures Financed With Internal Funds
APCo	$1,307	70%
I&M	645	100
OPCo	1,686	60
SWEPCo	414	100
TCC	531	100

Significant Factors

Possible Divestitures

AEP's management is firmly committed to continually evaluating the need to reallocate resources to areas that effectively match investments with our business strategy, providing the greatest potential for financial returns and to disposing of investments that no longer meet these goals.

TCC is seeking to divest significant components of its non-regulated domestic generation assets. In June 2003, TCC began actively seeking buyers for 4,497 megawatts of its generating capacity in Texas. The value received from this disposition will also be used to calculate stranded costs in Texas (see Note 6). Management is currently evaluating bids received during the fourth quarter of 2003 and is in negotiations to sell these assets. See Note 10 for discussion of impairments recorded related to the generating units in Texas. The ultimate sale of these assets may have a material impact on results of operations, cash flows and financial condition if losses are not recovered through the 2004 true-up proceeding in Texas.

Management continues to have periodic discussions with various parties on business alternatives for certain other investments. The ultimate timing for a disposition of one or more of these assets will depend upon market conditions and the value of any buyer's proposal.

Corporate Separation

In compliance with certain provisions in the Texas and Ohio restructuring laws, AEP filed in 2001 for regulatory approvals related to efforts at that time to separate regulated and unregulated operations, and amend certain affiliate pooling arrangements. Although certain regulatory approvals have been obtained, with the changes in the regulatory environment and AEP's business strategy, management continues to evaluate corporate separation plans.

In Texas, TCC is in the process of divesting its generating assets in accordance with provisions of the Texas Legislation concerning stranded cost recovery (see Note 6). In order to sell these assets, TCC anticipates retiring first mortgage bonds by making open market purchases or defeasing the bonds. Once such generating assets are sold, which management expect to be finalized in 2004, TCC will effectively accomplish the structural separation requirements of the Texas Legislation for those assets.

In Ohio, the PUCO has encouraged utilities to file rate stabilization plans to provide rate certainty and stability for customers who do not choose alternative suppliers, for the period of January 1, 2006 through December 31, 2008, which is after the expiration of the current market development period. On February 9, 2004, CSPCo and OPCo filed such a rate stabilization plan with the PUCO. The plan, in part, provides that both CSPCo and OPCo will remain functionally separated. Approval of the rate stabilization plan is currently pending before the PUCO.

Unless otherwise directed by the PUCO in an order on the rate stabilization plan, CSPCo and OPCo will remain functionally separated through at least the end of the rate stabilization plan period, December 31, 2008, and therefore, are not planning to legally separate, or to change the affiliate pooling agreement for the AEP East companies, in the foreseeable future.

Management continues to evaluate the most appropriate approach for complying with the Texas Legislation's structural separation requirements for TNC, including appropriate regulatory approvals to implement its structural separation.

RTO Formation

The FERC's AEP-CSW merger approval and many of the settlement agreements with the state regulatory commissions to approve the AEP-CSW merger required the transfer of functional control of our subsidiaries' transmission systems to RTOs. Further, legislation in some of AEP's states requires RTO participation.

In May 2002, AEP announced an agreement with PJM to pursue terms for participation in its RTO for AEP East companies with final agreements to be negotiated. In July 2002, FERC issued an order accepting our decision to participate in PJM, subject to specified conditions. AEP and other parties continue to work on the resolution of those conditions.

In December 2002, AEP's subsidiaries that operate in the states of Indiana, Kentucky, Ohio and Virginia filed for state regulatory commission approval of their plans to transfer functional control of their transmission assets to PJM. Proceedings in Ohio remain pending.

In February 2003, the state of Virginia enacted legislation preventing APCo from joining an RTO prior to July 1, 2004 and thereafter only with the approval of the Virginia SCC, but required such transfers by January 1, 2005. In January 2004, APCo filed a cost/benefit study with the Virginia SCC covering the time period through 2014 as required by the Virginia SCC. The study results show a net benefit of approximately $98 million for APCo over the 11-year study period from AEP's participation in PJM.

In July 2003, the KPSC denied KPCo's request to join PJM based in part on a lack of evidence that it would benefit Kentucky retail customers. In December 2003, AEP filed with the KPSC a cost/benefit study showing a net benefit of approximately $13 million for KPCo over the five-year study period from AEP's participation in PJM. A hearing has been scheduled in April 2004.

In September 2003, the IURC issued an order approving I&M's transfer of functional control over its transmission facilities to PJM, subject to certain conditions included in the order. The IURC's order stated that AEP shall request and the IURC shall complete a review of Alliance formation costs before any deferral of the costs for future recovery.

In April 2003, FERC approved our transfer of functional control of the AEP East companies' transmission system to PJM. FERC also accepted our proposed rates for joining PJM, but set a number of rate issues for resolution through settlement proceedings or FERC hearings. Settlement discussions continue on certain rate matters.

On September 29 and 30, 2003, the FERC held a public inquiry regarding RTO formation, including delays in AEP's participation in PJM. In November 2003, the FERC issued an order preliminarily finding that AEP must fulfill its CSW merger commitment to join an RTO by fully integrating into PJM (transmission and markets) by October 1, 2004. The FERC set several issues for public hearing before an ALJ. Those issues include whether the laws, rules, or regulations of Virginia and Kentucky are preventing AEP from joining an RTO and whether the states' provisions meet either of the two exceptions under PURPA. The FERC directed the ALJ to issue his initial decision by March 15, 2004.

If AEP East companies do not obtain regulatory approval to join PJM, they are committed to reimburse PJM for certain project implementation costs (presently estimated at $24 million for AEP's share of the entire PJM integration project). These costs, if incurred, will be allocated to the AEP East companies. AEP East companies also plan to seek recovery of deferred RTO formation/integration costs in the future. At December 31, 2003, the deferred amounts per company are as follows:

Company	(in millions)
APCo	$7.8
CSPCo	3.3
I&M	6.0
KPCo	1.8
OPCo	8.6

See Note 4 for further discussion.

AEP West companies are members of ERCOT or SPP. In 2002, FERC conditionally accepted filings related to a proposed consolidation of MISO and SPP. State public utility commissions also regulate AEP's SPP companies. The Louisiana and Arkansas commissions filed responses to the FERC's RTO order indicating that additional analysis was required. Subsequently, the proposed SPP/MISO combination was terminated. On October 15, 2003, SPP filed a proposal at the FERC for recognition as an RTO. In February 2004, the FERC granted RTO status to the SPP, subject to fulfilling specified requirements. Regulatory activities concerning various RTO issues are ongoing in Arkansas and Louisiana.

Management is unable to predict the outcome of these regulatory actions and proceedings or their impact on transmission operations, results of operations and cash flows or the timing and operation of RTOs.

Pension Plans

AEP maintains qualified defined benefit pension plans (Qualified Plans), which cover a substantial majority of non-union and certain union associates, and unfunded excess plans to provide benefits in excess of amounts permitted to be paid under the provisions of the tax law to participants in the Qualified Plans. Additionally, AEP has entered into individual retirement agreements with certain current and retired executives that provide additional retirement benefits.

AEP's net periodic pension expense was an income item for all pension plans approximating $3 million and $44 million for the years ended December 31, 2003 and 2002, respectively, and is calculated based upon a number of actuarial assumptions, including an expected long-term rate of return on the Qualified Plans' assets. In 2002 and 2003, the long-term return was assumed to be 9.00%, and for 2004, the long-term rate of return was lowered to 8.75%. In developing the expected long-term rate of return assumption, AEP evaluated input from actuaries and investment consultants, including their reviews of asset class return expectations as well as long-term inflation assumptions. Projected returns by such actuaries and consultants are based on broad equity and bond indices. AEP also considered historical returns of the investment markets as well as the 10-year average return, for the period ended December 2003, of approximately 10.0%. AEP anticipates that the investment managers it employs for the pension fund will continue to generate long-term returns of at least 8.75%.

The expected long-term rate of return on the Qualified Plan's assets is based on AEP's targeted asset allocation and expected investment returns for each investment category. AEP's assumptions are summarized in the following table:

	2003 Actual Asset Allocation	2004 Target Asset Allocation (in percentage)	Assumed/Expected Long-term Rate of Return
Equity	71	70	10.5
Fixed Income	27	28	5
Cash and Cash Equivalents	2	2	2
Total	100	100	
Overall Expected Return (weighted average)			8.75

AEP regularly reviews the actual asset allocation and periodically rebalances the investments to its targeted allocation when considered appropriate. AEP believes that 8.75% is a reasonable long-term rate of return on the Qualified Plans' assets despite the recent market volatility in which the Qualified Plans' assets had a loss of 11.2% for the twelve months ended December 31, 2002, and a gain of 23.8% for the twelve months ended December 31, 2003. AEP will continue to evaluate the actuarial assumptions, including the expected rate of return, at least annually, and will adjust them as necessary.

AEP bases its determination of pension expense or income on a market-related valuation of assets which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the market-related value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded. As of December 31, 2003, AEP has cumulative losses of approximately $325 million which remain to be recognized in the calculation of the market-related value of assets. These unrecognized net actuarial losses result in increases in the future pension costs depending on several factors, including whether such losses at each measurement date exceed the corridor in accordance with SFAS No. 87, "Employers' Accounting for Pensions."

The discount rate that AEP utilizes for determining future pension obligations is based on a review of long-term bonds that receive one of the two highest ratings given by a recognized rating agency. The discount rate determined on this basis has decreased from 6.75% at December 31, 2002, to 6.25% at December 31, 2003. Due to the effect of the unrecognized actuarial losses and based on an expected rate of return on the Qualified Plans' assets of 8.75%, a discount rate of 6.25% and various other assumptions, AEP estimates that the pension expense for all pension plans will approximate $41 million, $78 million and $103 million in 2004, 2005 and 2006, respectively. Future actual pension cost will depend on future investment performance, changes in future discount rates and various other factors related to the populations participating in the pension plans.

Lowering the expected long-term rate of return on the Qualified Plans' assets by 0.5% (from 9.0% to 8.5%) would have increased pension cost for 2003 by approximately $18 million (income of $3 million would have become $15 million in pension expense). Lowering the discount rate by 0.5% would have reduced pension income for 2003 by approximately $0.5 million.

The value of the Qualified Plans' assets has increased from $2.795 billion at December 31, 2002 to $3.180 billion at December 31, 2003. The Qualified Plans paid out $292 million in benefits to plan participants during 2003 (the nonqualified plans paid out $7 million in benefits). AEP's pension plans remain in an underfunded position (plan assets are less than projected benefit obligations) of $508 million at December 31, 2003. Due to the pension plans currently being underfunded, AEP recorded a charge to Other Comprehensive Income (OCI) of $585 million in 2002, and recorded a Deferred Income Tax Asset of $315 million, offset by a Minimum Pension Liability of $662 million and a reduction to prepaid costs and adjustment for unrecognized costs of $238 million. In 2003, the income recorded in OCI was $154 million, and the reduction in the Deferred Income Tax Asset was $76 million, offset by a reduction in Minimum Pension Liability of $234 million and a reduction to adjustment for

unrecognized costs of $4 million. The charge to OCI does not affect earnings or cash flow. AEP's plans are in compliance with the laws and regulations governing such plans including the Employee Retirement Income Security Act of 1974, as amended. Due to the current underfunded status of the Qualified Plans, AEP expects to make cash contributions to the pension plans of approximately $41 million in 2004.

Certain of the defined benefit pension plans AEP sponsors and maintains contain a cash balance benefit feature. In recent years, cash balance benefit features have become a focus of scrutiny, as government regulators and courts consider how the Employee Retirement Income Security Act of 1974, as amended, the Age Discrimination in Employment Act, as amended, and other relevant federal employment laws apply to plans with such a cash balance plan feature. AEP believes that the defined benefit pension plans it sponsors and maintains are in substantial compliance with the applicable requirements of such laws.

See Note 11 of the Notes to Respective Financial Statements for additional information related to the impact of pension plans on individual AEP registrant subsidiaries.

Nuclear Plant Outages

In April 2003, engineers at STP, during inspections conducted regularly as part of refueling outages, found wall cracks in two bottom mounted instrument guide tubes of STP Unit 1. These tubes were repaired and the unit returned to service in August 2003. TCC's share of the cost of repair for this outage was approximately $6 million. TCC had commitments to provide power to customers during the outage. Therefore, TCC was subject to fluctuations in the market prices of electricity and purchased replacement energy.

In April 2003, both units of Cook Plant were taken offline due to an influx of fish in the plant's cooling water system which caused a reduction in cooling water to essential plant equipment. After repair of damage caused by the fish intrusion, Cook Plant Unit 1 returned to service in May and Unit 2 returned to service in June following completion of a scheduled refueling outage.

Litigation

Federal EPA Complaint and Notice of Violation

See discussion of New Source Review Litigation under "Environmental Matters".

Enron Bankruptcy

On October 15, 2002, certain subsidiaries of AEP filed claims against Enron and its subsidiaries in the bankruptcy proceeding filed by the Enron entities which are pending in the U.S. Bankruptcy Court for the Southern District of New York. At the date of Enron's bankruptcy, certain subsidiaries of AEP had open trading contracts and trading accounts receivables and payables with Enron. In addition, on June 1, 2001, AEP purchased Houston Pipe Line Company (HPL) from Enron. Various HPL related contingencies and indemnities from Enron remained unsettled at the date of Enron's bankruptcy. The timing of the resolution of the claims by the Bankruptcy Court is not certain.

In September 2003, Enron filed a complaint in the Bankruptcy Court against AEPES challenging AEP's offsetting of receivables and payables and related collateral across various Enron entities and seeking payment of approximately $125 million plus interest in connection with gas related trading transactions. AEP will assert its right to offset trading payables owed to various Enron entities against trading receivables due to several AEP subsidiaries. Management is unable to predict the outcome of this lawsuit or its impact on results of operations, cash flows or financial condition.

In December 2003, Enron filed a complaint in the Bankruptcy Court against AEPSC seeking approximately $93 million plus interest in connection with a transaction for the sale and purchase of physical power among Enron, AEP and Allegheny Energy Supply, LLC during November 2001. Enron's claim seeks to unwind the effects of the transaction. AEP believes it has several defenses to the claims in the action being brought by Enron. Management is unable to predict the outcome of this lawsuit or its impact on results of operations, cash flows or financial condition.

During 2002 and 2001, AEP subsidiaries expensed a total of $53 million ($34 million net of tax) for their estimated loss from the Enron bankruptcy. The amounts for certain subsidiaries were:

Registrant	Amounts Expensed	Amounts Net of Tax
	(in millions)	
APCo	$5.3	$3.4
CSPCo	2.7	1.8
I&M	2.8	1.8
KPCo	1.1	0.7
OPCo	3.6	2.3

The amounts expensed were based on an analysis of contracts where AEP and Enron entities are counterparties, the offsetting of receivables and payables, the application of deposits from Enron entities and management's analysis of the HPL related purchase contingencies and indemnifications. As noted above, Enron has challenged the offsetting of receivables and payables. Management is unable to predict the final resolution of these disputes, however the impact on results of operations, cash flows and financial condition could be material.

Energy Market Investigations

AEP and other energy market participants received data requests, subpoenas and requests for information from the FERC, the SEC, the PUCT, the U.S. Commodity Futures Trading Commission (CFTC), the U.S. Department of Justice and the California attorney general during 2002. Management responded to the inquiries and provided the requested information and has continued to respond to supplemental data requests in 2003 and 2004.

In March 2003, AEP received a subpoena from the SEC as part of the SEC's ongoing investigation of energy trading activities. In August 2002, AEP received an informal data request from the SEC seeking that AEP voluntarily provide information. The subpoena sought additional information and is part of the SEC's formal investigation. AEP responded to the subpoena and will continue to cooperate with the SEC.

On September 30, 2003, the CFTC filed a complaint against AEP and AEPES in federal district court in Columbus, Ohio. The CFTC alleges that AEP and AEPES provided false or misleading information about market conditions and prices of natural gas in an attempt to manipulate the price of natural gas in violation of the Commodity Exchange Act. The CFTC seeks civil penalties, restitution and disgorgement of benefits. The case is in the initial pleading stage with our response to the complaint currently due on May 18, 2004. Although management is unable to predict the outcome of this case, AEP recorded a provision in 2003 and the action is not expected to have a material effect on results of operations.

In January 2004, the CFTC issued a request for documents and other information in connection with a CFTC investigation of activities affecting the price of natural gas in the fall of 2003. AEP is responding to that request.

Management cannot predict what, if any further action, any of these governmental agencies may take with respect to these matters.

TEM Litigation

See discussion of TEM litigation within OPCo's Management's Financial Discussion and Analysis.

Texas Commercial Energy, LLP Lawsuit

Texas Commercial Energy, LLP (TCE), a Texas REP, filed a lawsuit against AEP and four of its subsidiaries including TCC and TNC, certain unaffiliated energy companies and ERCOT alleging violations of the Sherman Antitrust Act, fraud, negligent misrepresentation, breach of fiduciary duty, breach of contract, civil conspiracy and negligence. The allegations, not all of which are made against the AEP companies, range from anticompetitive bidding to withholding power. TCE alleges that these activities resulted in price spikes requiring TCE to post additional collateral and ultimately forced it into bankruptcy when it was unable to raise prices to its customers due to fixed price contracts. The suit alleges over $500 million in damages for all defendants and seeks recovery of damages, exemplary damages and court costs. Management believes that the claims against AEP and its subsidiaries are without merit. Management intends to vigorously defend against the claims. See Note 7 for further discussion.

COLI Litigation

A decision by the U.S. District Court for the Southern District of Ohio in February 2001 that denied AEP's deduction of interest claimed on AEP's consolidated federal income tax returns related to a COLI program resulted in a $319 million reduction in AEP's Net Income for 2000.

The earnings reductions for affected registrant subsidiaries were as follows:

	(in millions)
APCo	$82
CSPCo	41
I&M	66
KPCo	8
OPCo	118

AEP filed an appeal of the U.S. District Court's decision with the U.S. Court of Appeals for the 6th Circuit. In April 2003, the Appeals Court ruled against AEP. The U.S. Supreme Court has declined to hear this issue.

Other Litigation

AEP subsidiaries are involved in a number of other legal proceedings and claims. While management is unable to predict the outcome of such litigation, it is not expected that the ultimate resolution of these matters will have a material adverse effect on results of operations, cash flows or financial condition.

Potential Uninsured Losses

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including, but not limited to, liabilities relating to damage to the Cook Plant or STP and costs of replacement power in the event of a nuclear incident at the Cook Plant or STP. Future losses or liabilities which are not completely insured, unless recovered from customers, could have a material adverse effect on results of operations, cash flows and financial condition.

Environmental Matters

There are new environmental control requirements that management expects will result in substantial capital investments and operational costs. The sources of these future requirements include:

- Legislative and regulatory proposals to adopt stringent controls on sulfur dioxide (SO_2), nitrogen oxide (NO_x) and mercury emissions from coal-fired power plants,

- New Clean Water Act rules to reduce the impacts of water intake structures on aquatic species at certain of our power plants, and
- Possible future requirements to reduce carbon dioxide emissions to address concerns about global climatic change.

In addition to achieving full compliance with all applicable legal requirements, AEP subsidiaries strive to go beyond compliance in an effort to be good environmental stewards. For example, AEP subsidiaries invest in research, through groups like the Electric Power Research Institute, to develop, implement and demonstrate new emission control technologies. AEP subsidiaries plan to continue in a leadership role to protect and preserve the environment while providing vital energy commodities and services to customers at fair prices. AEP subsidiaries have a proven record of efficiently producing and delivering electricity while minimizing the impact on the environment. The AEP System has invested over $2 billion, from 1990 through 2003, to equip many of its facilities with pollution control technologies. The AEP System will continue to make investments to improve the air emissions from its generating stations because this is the most cost-effective generation source for its customers electricity needs.

The Current Air Quality Regulatory Framework

The Clean Air Act (CAA) is the legislation that establishes the federal regulatory authority and oversight for emissions from fossil-fired generating plants. The states, with oversight and approval from the Federal EPA, administer and enforce these laws and related regulations.

Title I of the CAA

National Ambient Air Quality Standards: The Federal EPA periodically reviews the available scientific data for six pollutants and establishes a standard for concentration levels in ambient air for these substances to protect the public welfare and public health with an extra margin for safety. These requirements are known as "national ambient air quality standards" (NAAQS).

The states identify those areas within their state that meet the NAAQS (attainment areas) and those that do not (non-attainment areas). States must develop their individual state implementation plans (SIPs) with the intention of bringing non-attainment areas into compliance with the NAAQS. In developing a SIP each state must allow attainment areas to maintain compliance with the NAAQS. This is accomplished by controlling sources that emit one or more pollutants or precursors to those pollutants. The Federal EPA approves SIPs if they meet the minimum criteria in the CAA. Alternatively, the Federal EPA may prescribe a federal implementation plan if they conclude that a SIP is deficient. Additionally, the Federal EPA can impose sanctions, up to and including withholding of federal highway funds, in states that fail to submit an adequate SIP or a SIP that fails to bring non-attainment areas into NAAQS compliance within the time prescribed by the CAA.

The CAA also establishes visibility goals, which are known as the regional haze program, for certain federally designated areas, including national parks. States are required to develop and submit SIP provisions that will demonstrate reasonable progress toward preventing the impairment and remedying any existing impairment of visibility in these federally designated areas.

Each state's SIP must include requirements to control sources that emit pollutants in that state as well as requirements to control sources that significantly contribute to non-attainment areas in another state. If a state believes that its air quality is impacted by upwind sources outside their borders, that state can submit a petition that asks the Federal EPA to impose control requirements on specific sources in other states if those states' SIPs do not contain adequate requirements to control those sources. For example, the Federal EPA issued a NOx Rule in 1997, which affected 22 eastern states (including states in which AEP subsidiaries operate) and the District of Columbia. The NOx Rule asked these 23 jurisdictions to adopt requirements, for utility and industrial boilers and certain other emission sources, to employ cost-effective control technologies to reduce NOx emissions. The purpose of the request was to allow certain eastern states to reduce the contribution from these 23 jurisdictions to ozone non-attainment areas in certain eastern states.

The Federal EPA also granted four petitions filed by certain eastern states seeking essentially the same levels of control on emission sources outside of their states and issued a Section 126 Rule. All of the states in which we operate that were subject to the NOx Rule have submitted the required SIP revisions. In response, the Federal EPA issued the NOx Rule and the Section 126 Rule, which are discussed below.

The compliance date for the NOx Rule is May 31, 2004. In 2000, the Federal EPA also adopted a revised Section 126 Rule which granted petitions filed by four northeastern states. The revised Section 126 Rule imposes emissions reduction requirements comparable to the NOx Rule also beginning May 31, 2004, for most of our coal-fired generating units.

In 2000, the Texas Commission on Environmental Quality adopted rules requiring significant reductions in NOx emissions from utility sources, including TCC and SWEPCo. The compliance requirements began in May 2003 for TCC and begin in May 2005 for SWEPCo.

AEP subsidiaries are installing a variety of emission control technologies to improve NOx emissions standards and to comply with applicable state and federal NOx requirements. These include selective catalytic reduction (SCR) technology on certain units and other combustion control technologies on a larger number of units.

AEP's electric utility units are currently subject to SIP requirements that control SO_2 and particulate matter emissions in all states, and that control NOx emissions in certain states. The AEP System's generating plants comply with applicable SIP limits for SO_2, NOx and particulate matter.

Hazardous Air Pollutants: In 1990 Amendments to the CAA, Congress required the Federal EPA to identify the sources of 188 hazardous air pollutants (HAPs) and to develop regulations that prescribe a level of HAP emission reduction. These reductions must reflect the application of maximum achievable control technology (MACT). Congress also directed the Federal EPA to investigate HAP emissions from the electric utility sector and to submit a report to Congress. The Federal EPA's 1998 report to Congress identified mercury emissions from coal-fired electric utility units and nickel emissions from oil-fired utility units as sources of HAP emissions that warranted further investigation and possible control.

New Source Performance Standards and New Source Review: The Federal EPA establishes New Source Performance Standards (NSPS) for 28 categories of major stationary emission sources that reflect the best demonstrated level of pollution control. Sources that are constructed or modified after the effective date of an NSPS standard are required to meet those limitations. For example, many electric utility units are regulated under the NSPS for SO_2, NOx, and particulate matter. Similarly, each SIP must include regulations that require new sources, and major modifications at existing emission sources that result in a significant net increase in emissions, to submit a permit application and undergo a review of available technologies to control emissions of pollutants. These rules are called new source review (NSR) requirements.

Different NSR requirements apply in attainment and non-attainment areas.

In attainment areas:

- An air quality review must be performed, and
- The best available control technology must be employed to reduce new emissions.

In non-attainment areas,

- Requirements reflecting the lowest achievable emission rate are applied to new or modified sources, and
- All new emissions must be offset by reductions in emissions of the same pollutant from other sources within the same control area.

Neither the NSPS nor NSR requirements apply to certain activities, including routine maintenance, repair or replacement, changes in fuels or raw materials that a source is capable of accommodating, the installation of a pollution control project, and other specifically excluded activities.

Title IV of the CAA (Acid Rain)

The 1990 Amendments to the CAA included a market-based emission reduction program designed to reduce the amount of SO_2 emitted from electric utility units by approximately 50 percent from 1980 levels. This program also established a nationwide cap on utility SO_2 emissions of 8.9 million tons per year. The Federal EPA administers its SO_2 program through an allowance allocation and trading system. Allowances are allocated to specific units based on statutory formulas. Annually each utility unit must surrender one allowance for each ton of SO_2 that it emits. Emission sources that install controls and no longer need all of their allowances can bank those allowances for future use or trade them to other emission sources.

Title IV also contains requirements for utility sources to reduce NOx emissions through the use of available combustion controls. Units must meet NOx emission rates standards which are specific to that unit or units may participate in an annual averaging program for utility units that are under common control.

Future Reduction Requirements for SO_2, NOx, and Mercury

In 1997, the Federal EPA adopted new, more stringent NAAQS for fine particulate matter and ground-level ozone. The Federal EPA is in the process of developing final designations for fine particulate matter and ground-level ozone non-attainment areas. The Federal EPA has identified SO_2 and NOx emissions as precursors to the formation of fine particulate matter. NOx emissions are also identified as a precursor to the formation of ground-level ozone. As a result, requirements for future reductions in emissions of NOx and SO_2 from the AEP System's generating units are highly probable. In addition, the Federal EPA has proposed a set of options for future mercury controls at coal-fired power plants.

Multi-emission control legislation, known as the Clear Skies Act, was introduced in Congress and is supported by the Bush Administration. This legislation would regulate NOx, SO_2, and mercury emissions from electric generating plants. AEP supports enactment of this comprehensive, multi-emission legislation so that compliance planning can be coordinated and collateral emission reductions maximized. Management believes the Bush Administration's Clear Skies Act would establish stringent emission reduction targets and achievable compliance timetables utilizing a cost-effective nationwide cap and trade program. Although the prospects for enactment of the Clear Skies Act are low, there are alternative regulatory approaches which will likely require the AEP System to substantially reduce SO_2, NOx and mercury emissions over the next ten years.

Regulatory Emissions Reductions

On January 30, 2004, the Federal EPA published two proposed rules that would collectively require reductions of approximately 70% in emissions of SO_2, NOx and mercury from coal-fired electric generating units by 2015 (2018 for mercury). This initiative has two major components:

- The Federal EPA proposed an interstate air quality rule for reducing SO_2 and NOx emissions across the eastern half of the United States (29 states and the District of Columbia) to address attainment of the fine particulate matter and ground-level ozone NAAQS. These reductions could also satisfy these states' obligations to make reasonable progress towards the national visibility goal under the regional haze program.
- The Federal EPA proposed to regulate mercury emissions from coal-fired electric generating units.

The interstate air quality rule would require affected states to include, in their SIPs, a program to reduce NOx and SO_2 emissions from coal-fired electric utility units. SO_2 and NOx emissions would be reduced in two phases, which would be implemented through a cap-and-trade program. Regional SO_2 emissions would be reduced to 3.9 million tons by 2010 and to 2.7 million tons by 2015. Regional NOx emissions would be reduced to 1.6 million tons by 2010 and to 1.3 million tons by 2015. Rules to implement the SO_2 and NOx trading programs have not yet been proposed.

To control and reduce mercury emissions, the Federal EPA published two alternative proposals. The first option requires the installation of MACT on a site-specific basis. Mercury emissions would be reduced from 48 tons to approximately 34 tons by 2008. The Federal EPA believes, and the industry concurs, that there are no

commercially available mercury control technologies in the marketplace today that can achieve the MACT standards for bituminous coals, but certain units have achieved comparable levels of mercury reduction by installing conventional SO_2 (scrubbers) and NOx (SCR) emission reduction technologies. The proposed rule imposes significantly less stringent standards on generating plants that burn sub-bituminous coal or lignite, which standards potentially could be met without installation of mercury control technologies.

The Federal EPA recommends, and AEP supports, a second mercury emission reduction option. The second option would permit mercury emission reductions to be achieved from existing sources through a national cap-and-trade approach. The cap-and-trade approach would include a two-phase mercury reduction program for coal-fired utilities. This approach would coordinate the reduction requirements for mercury with the SO_2 and NOx reduction requirements imposed on the same sources under the proposed interstate air quality rule. Coordination is significantly more cost-effective because technologies like scrubbers and SCRs, that can be used to comply with the more stringent SO_2 and NOx requirements, have also proven highly effective in reducing mercury emissions on certain coal-fired units that burn bituminous coal. The second option contemplates reducing mercury emissions from 48 million tons to 34 million tons by 2010 and to 15 million tons by 2018.

The Federal EPA's proposals are the beginning of a lengthy rulemaking process, which will involve supplemental proposals on many details of the new regulatory programs, written comments and public hearings, issuance of final rules, and potential litigation. In addition, states have substantial discretion in developing their rules to implement cap-and-trade programs, and will have 18 months after publication of the notice of final rulemaking to submit their revised SIPs. As a result, the ultimate requirements may not be known for several years and may depart significantly from the original proposed rules described here.

While uncertainty remains as to whether future emission reduction requirements will result from new legislation or regulation, it is certain under either outcome that AEP subsidiaries will invest in additional conventional pollution control technology on a major portion of their coal-fired power plants. Finalization of new requirements for further SO_2, NOx and/or mercury emission reductions will result in the installation of additional scrubbers, SCR systems and/or the installation of emerging technologies for mercury control.

Estimated Air Quality Environmental Investments

Each of the current and possible future environmental compliance requirements discussed above will require significant additional investments, some of which are estimable. The proposed rules discussed above have not been adopted, will be subject to further revision, and will be the subject of a court challenge and further modifications.

All of management's estimates are subject to significant uncertainties about the outcome of several interrelated assumptions and variables, including:

- Timing of implementation
- Required levels of reductions
- Allocation requirements of the new rules, and
- Selected compliance alternatives.

As a result, management cannot estimate compliance costs with certainty, and the actual costs to comply could differ significantly from the estimates discussed below.

All of the costs discussed below are incremental to the AEP subsidiaries' current investment base and operating cost structure. These expenditures for pollution control technologies, replacement generation and associated operating costs are recoverable from customers through regulated rates (in regulated jurisdictions) and should be recoverable through market prices (in deregulated jurisdictions). If not, those costs could adversely affect future results of operations, cash flows and possibly financial condition.

Estimated Investments for NOx Compliance

Management estimates that AEP subsidiaries will make future investments of approximately $600 million to comply with the Federal EPA's NOx Rule, the Texas Commission on Environmental Quality Rule and other final Federal EPA NOx-related requirements. Approximately $500 million of these investments are reflected in the estimated construction expenditures for 2004 – 2006. As of December 31, 2003, the AEP System has invested approximately $1.1 billion to comply with various NOx requirements. Estimated future compliance costs, amounts in the 2004 – 2006 construction budget and amounts spent by subsidiaries are as follows:

	Future Estimated Compliance Investment	Investment Amount in 2004 – 2006 Budget	Amount Spent
		(in millions)	
AEGCo	$10	$9	$12
APCo	151	151	307
CSPCo	63	29	71
I&M	10	9	17
KPCo	11	1	179
OPCo	305	273	442
PSO	8	8	-
SWEPCo	18	12	23
TCC	-	-	5

Estimated Investments for SO2 Compliance

The AEP System is complying with Title IV SO_2 requirements by installing scrubbers, other controls and fuel switching at certain generating units. AEP subsidiaries also use SO_2 allowances that were:

- Received in the annual allowance allocation by the Federal EPA,
- Obtained through participation in the annual allowance auction,
- Purchased in the allowance market, and
- Obtained as bonus allowances for installing controls early.

Decreasing SO_2 allowance allocations, a diminishing SO_2 allowance bank, and increasing allowance prices in the market will require the installation of additional controls on certain generating units. AEP subsidiaries plan to install 3,500 MW of additional scrubbers over the next 4 years to comply with our Title IV SO_2 obligations. In total management estimates these additional capital costs to be approximately $1.2 billion. Of this total, approximately $900 million will be expended during 2004-2006 and this amount is included in total estimated construction expenditures for 2004 – 2006. The following table shows the estimated additional capital costs and amounts included in the 2004 – 2006 budget for additional scrubbers by subsidiary:

	Cost of Additional Scrubbers	Amount in 2004 – 2006 Construction Budget
	(in millions)	
APCo	$367	$307
OPCo	753	542
SWEPCo	27	21
TNC	16	16

Estimated Investments to Comply with Future Reduction Requirements

The AEP System's planning assumptions for the levels and timing of emissions reductions parallel the reduction levels and implementation time periods stated in the proposed rules issued by the Federal EPA in January 2004. Management has also assumed that the Federal EPA will implement a mercury trading option and will design its proposed cap and trade mechanism for SO_2, NOx and mercury emissions in a manner similar to existing cap and trade programs. Based on these assumptions, compliance would require additional capital investment of approximately $1.7 billion by 2010, the end of the first phase for each proposed rule. Management estimates that the subsidiaries will invest $200 million of this amount through 2006, and this amount is included in our total estimated construction expenditures for 2004 – 2006.

	Estimated Compliance Investments	Amount in 2004 – 2006 Budget
	(in millions)	
APCo	$698	$79
CSPCo	184	4
KPCo	295	36
OPCo	454	103
SWEPCo	94	-

Management also estimates that the subsidiaries would incur increases in variable operation and maintenance expenses of $150 million for the periods by 2010, due to the costs associated with the maintenance of additional control systems, disposal of scrubber by-products and the purchase of reagents.

If the Federal EPA's preferred mercury trading option is not implemented, then any alternative mercury control program requiring adherence to MACT standards would also have implementation costs that could be significant. Management cannot currently estimate the nature or amount of these costs. Furthermore, scrubber and SCR technologies could not be deployed at every bituminous-fired plant that the AEP System operates within the three-year compliance schedule provided under the proposed MACT rule. These MACT compliance costs, which management is not able to estimate, would be incremental to other cost estimates that are discussed above.

Beyond 2010, the AEP System expects to incur additional costs for pollution control technology retrofits and associated operation and maintenance of the equipment. Management cannot estimate these additional costs because of the uncertainties associated with the final control requirements and the associated compliance strategy, but these capital and operating costs will be significant.

New Source Review Litigation

Under the CAA, if a plant undertakes a major modification that directly results in an emissions increase, permitting requirements might be triggered and the plant may be required to install additional pollution control technology. This requirement does not apply to activities such as routine maintenance, replacement of degraded equipment or failed components, or other repairs needed for the reliable, safe and efficient operation of the plant.

The Federal EPA and a number of states alleged APCo, CSPCo, I&M, OPCo and other unaffiliated utilities modified certain units at coal-fired generating plants in violation of the NSRs of the CAA. The Federal EPA filed its complaints against AEP subsidiaries in U.S. District Court for the Southern District of Ohio. The court also consolidated a separate lawsuit, initiated by certain special interest groups, with the Federal EPA case. The alleged modifications relate to costs that were incurred at the generating units over a 20-year period.

Management is unable to estimate the loss or range of loss related to the contingent liability for civil penalties under the CAA proceedings. Management is also unable to predict the timing of resolution of these matters due to the number of alleged violations and the significant number of issues yet to be determined by the Court. If the AEP System companies do not prevail, any capital and operating costs of additional pollution control equipment that may be required, as well as any penalties imposed, would adversely affect future results of operations, cash flows and possibly financial condition unless such costs can be recovered through regulated rates and market prices for electricity.

Superfund and State Remediation

By-products from the generation of electricity include materials such as ash, slag, sludge, low-level radioactive waste and SNF. Coal combustion by-products, which constitute the overwhelming percentage of these materials, are typically disposed of or treated in captive disposal facilities or are beneficially utilized. In addition, our generation plants and transmission and distribution facilities have used asbestos, PCBs and other hazardous and non-hazardous materials. AEP subsidiaries are currently incurring costs to safely dispose of these substances.

Superfund addresses clean-up of hazardous substances at disposal sites and authorized the Federal EPA to administer the clean-up programs. As of year-end 2003, APCo, CSPCo, I&M and OPCo are each named by the Federal EPA as a PRP for one site. There are six additional sites for which APCo, CSPCo, I&M, KPCo, OPCo and SWEPCo have received information requests which could lead to PRP designation. OPCo and TCC have also been named potentially liable at four sites under state law. Liability has been resolved for a number of sites with no significant effect on results of operations. In those instances where AEP subsidiaries have been named a PRP or defendant, disposal or recycling activities were in accordance with the then-applicable laws and regulations. Unfortunately, Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories.

While the potential liability for each Superfund site must be evaluated separately, several general statements can be made regarding potential future liability. Disposal of materials by an AEP subsidiary at a particular site is often unsubstantiated and the quantity of materials deposited at a site was small and often nonhazardous. Although superfund liability has been interpreted by the courts as joint and several, typically many parties are named as PRPs for each site and several of the parties are financially sound enterprises. Therefore, present estimates do not anticipate material cleanup costs for identified sites for which AEP subsidiaries have been declared PRPs. If significant cleanup costs are attributed to any AEP subsidiary in the future under Superfund, its results of operations, cash flows and possibly financial condition would be adversely affected unless the costs can be included in its electricity prices.

Global Climate Change

At the Third Conference of the Parties to the United Nations Framework Convention on Climate Change held in Kyoto, Japan in December 1997, more than 160 countries, including the U.S., negotiated a treaty requiring legally-binding reductions in emissions of greenhouse gases, chiefly CO_2, which many scientists believe are contributing to global climate change. The U.S. signed the Kyoto Protocol on November 12, 1998, but the treaty was not submitted to the Senate for its advice and consent by President Clinton. In March 2001, President Bush announced his opposition to the treaty. Ratification of the treaty by a majority of the countries' legislative bodies is required for it to be enforceable. Enforceability of the protocol is now contingent on ratification by Russia, which has expressed concerns about doing so.

On August 28, 2003, the Federal EPA issued a decision in response to a petition for rulemaking seeking reductions of CO_2 and other greenhouse gas emissions from mobile sources. The Federal EPA denied the petition and issued a memorandum stating that it does not have the authority under the CAA to regulate CO_2 or other greenhouse gas emissions that may affect global warming trends. The Circuit Court of Appeals for the District of Columbia is reviewing these actions.

AEP does not support the Kyoto Protocol but has been working with the Bush Administration on a voluntary program aimed at meeting the President's goal of reducing the greenhouse gas intensity of the economy by 18% by 2012. For many years, AEP has been a leader in pursuing voluntary actions to control greenhouse gas emissions. AEP expanded its commitment in this area in 2002 by joining the Chicago Climate Exchange, a pilot greenhouse gas emission reduction and trading program, under which AEP's subsidiaries are obligated to reduce or offset 18 million tons of CO_2 emissions during 2003-2006.

Costs for Spent Nuclear Fuel and Decommissioning

I&M, as the owner of the Cook Plant, and TCC, as a partial owner of STP, have a significant future financial commitment to safely dispose of SNF and to decommission and decontaminate the plants. The Nuclear Waste Policy Act of 1982 established federal responsibility for the permanent off-site disposal of SNF and high-level radioactive waste. By law I&M and TCC participate in the DOE's SNF disposal program which is described in Note 7. Since 1983 I&M has collected $316 million from customers for the disposal of nuclear fuel consumed at the Cook Plant. We deposited $117 million of these funds in external trust funds to provide for the future disposal of SNF and remitted $199 million to the DOE. TCC has collected and remitted to the DOE, $56 million for the future disposal of SNF since STP began operation in the late 1980s. Under the provisions of the Nuclear Waste Policy Act, collections from customers are to provide the DOE with money to build a permanent repository for spent fuel. However, in 1996, the DOE notified the companies that it would be unable to begin accepting SNF by the January 1998 deadline required by law. To date, the DOE has failed to comply with the requirements of the Nuclear Waste Policy Act.

As a result of DOE's failure to make sufficient progress toward a permanent repository or otherwise assume responsibility for SNF, AEP on behalf of I&M and STPNOC on behalf of TCC and the other STP owners, along with a number of unaffiliated utilities and states, filed suit in the D.C. Circuit Court requesting, among other things, that the D.C. Circuit Court order DOE to meet its obligations under the law. The D.C. Circuit Court ordered the parties to proceed with contractual remedies but declined to order DOE to begin accepting SNF for disposal. DOE estimates its planned site for the nuclear waste will not be ready until at least 2010. In 1998, AEP and I&M filed a complaint in the U.S. Court of Federal Claims seeking damages in excess of $150 million due to the DOE's partial material breach of its unconditional contractual deadline to begin disposing of SNF generated by the Cook Plant. Similar lawsuits were filed by other utilities. In August 2000, in an appeal of related cases involving other unaffiliated utilities, the U.S. Court of Appeals for the Federal Circuit held that the delays clause of the standard contract between utilities and the DOE did not apply to DOE's complete failure to perform its contract obligations, and that the utilities' suits against DOE may continue in court. On January 17, 2003, the U.S. Court of Federal Claims ruled in favor of I&M on the issue of liability. The case continues on the issue of damages owed to I&M by the DOE with a trial scheduled in March 2004. As long as the delay in the availability of a government approved storage repository for SNF continues, the cost of both temporary and permanent storage of SNF and the cost of decommissioning will continue to increase.

The cost to decommission nuclear plants is affected by both NRC regulations and the delayed SNF disposal program. Studies completed in 2003 estimate the cost to decommission the Cook Plant ranges from $821 million to $1.08 billion in 2003 non-discounted dollars. External trust funds have been established with amounts collected from customers to decommission the plant. At December 31, 2003, the total decommissioning trust fund balance for Cook Plant was $720 million which includes earnings on the trust investments. Studies completed in 1999 for STP estimate TCC's share of decommissioning cost to be $289 million in 1999 non-discounted dollars. Amounts collected from customers to decommission STP have been placed in an external trust. At December 31, 2003, the total decommissioning trust fund for TCC's share of STP was $125 million which includes earnings on the trust investments. Estimates from the decommissioning studies could continue to escalate due to the uncertainty in the SNF disposal program and the length of time that SNF may need to be stored at the plant site. I&M and TCC will work with regulators and customers to recover the remaining estimated costs of decommissioning Cook Plant and STP. However, future results of operations, cash flows and possibly financial condition would be adversely affected if the cost of SNF disposal and decommissioning continues to increase and cannot be recovered.

Clean Water Act Regulation

On February 16, 2004, the Federal EPA signed a rule pursuant to the Clean Water Act that will require all large existing power plants to meet certain performance standards to reduce the mortality of juvenile and adult fish or other larger organisms pinned against a plant's cooling water intake screens. A subset of these plants that are located on sensitive water bodies will be required to meet additional performance standards for reducing the number of smaller organisms passing through the water screens and the cooling system. Sensitive water bodies are defined as oceans, estuaries, the Great Lakes, and small rivers with large plants. These rules will result in additional capital and operation and maintenance expenses to ensure compliance.

Other Environmental Concerns

We perform environmental reviews and audits on a regular basis for the purpose of identifying, evaluating and addressing environmental concerns and issues. In addition to the matters discussed above, the AEP subsidiaries are managing other environmental concerns which are not believed to be material or potentially material at this time. If they become significant or if any new matters arise that could be material, they could have a material adverse effect on results of operations, cash flows and possibly financial condition.

Critical Accounting Policies

In the ordinary course of business, we use a number of estimates and assumptions relating to the reporting of results of operations and financial condition in the preparation of our financial statements in conformity with accounting principles generally accepted in the United States of America. Actual results could differ significantly from those estimates under different assumptions and conditions. We believe that the following discussion addresses the most critical accounting policies, which are those that are most important to the portrayal of the financial condition and results and require management's most difficult, subjective and complex judgments, often as a result of the need to make estimates about the effect of matters that are inherently uncertain.

Revenue Recognition

Regulatory Accounting

The consolidated financial statements of the registrant subsidiary companies with cost-based rate-regulated operations (I&M, KPCo, PSO, and a portion of APCo, OPCo, CSPCo, TCC, TNC and SWEPCo), reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate regulated. In accordance with SFAS 71, regulatory assets (deferred expenses to be recovered in the future) and regulatory liabilities (deferred future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues in the same accounting period and by matching income with its passage to customers through regulated revenues in the same accounting period. Regulatory liabilities (unrealized gains) or regulatory assets (unrealized losses) are also recorded for changes in the fair value of physical and financial contracts that meet the definition of a derivative as defined in SFAS 133 and are subject to the regulated ratemaking process.

When regulatory assets are probable of recovery through regulated rates, certain registrant subsidiaries record them as assets on the balance sheet. Registrant subsidiaries test for probability of recovery whenever new events occur, for example a regulatory commission order or passage of new legislation. If registrant subsidiaries determine that recovery of a regulatory asset is no longer probable, they write off that regulatory asset as a charge against net income. A write off of regulatory assets may also reduce future cash flows since there may be no recovery through regulated rates.

Traditional Electricity Supply and Delivery Activities

Revenues are recognized on the accrual or settlement basis for normal retail and wholesale electricity supply sales and electricity transmission and distribution delivery services. The revenues are recognized and recorded when the energy is delivered to the customer and include estimated unbilled as well as billed amounts. In general, expenses are recorded when purchased electricity is received and when expenses are incurred.

Energy Marketing and Risk Management Activities

Registrant subsidiaries engage in wholesale electricity, natural gas and coal marketing and risk management activities. Effective in October 2002, these activities were focused on wholesale markets where registrant subsidiaries own assets. Registrant subsidiaries activities include the purchase and sale of energy under forward contracts at fixed and variable prices and the buying and selling of financial energy contracts which include exchange traded futures and options, and over-the-counter options and swaps. Prior to October 2002, registrant subsidiaries recorded wholesale marketing and risk management activities using the mark-to-market method of accounting.

In October 2002, EITF 02-3 precluded mark-to-market accounting for risk management contracts that were not derivatives pursuant to SFAS 133. Registrant subsidiaries implemented this standard for all non-derivative wholesale and risk management transactions occurring on or after October 25, 2002. For non-derivative risk management transactions entered into prior to October 25, 2002, registrant subsidiaries implemented this standard on January 1, 2003 and reported the effects of implementation as a cumulative effect of an accounting change.

After January 1, 2003, registrant subsidiaries use mark-to-market accounting for wholesale marketing and risk management transactions that are derivatives unless the derivative is designated for hedge accounting or the normal purchase and sale exemption. Revenues and expenses are recognized from wholesale marketing and risk management transactions that are not derivatives when the commodity is delivered.

See discussion of EITF 02-3 and rescission of EITF 98-10 in Note 2.

All of the registrant subsidiaries except AEGCo participate in wholesale marketing and risk management activities in electricity and gas. For I&M, KPCo, PSO and a portion of TNC and SWEPCo, when the contract settles the total gain or loss is realized in revenues. Where the revenues are recorded on the income statement depends on whether the contract is subject to the regulated ratemaking process. For contracts subject to the regulated ratemaking process the total gain or loss realized for sales and the cost of purchased energy are included in revenues on a net basis. Prior to settlement, changes in the fair value of physical and financial forward sale and purchase contracts subject to the regulated ratemaking process are deferred as regulatory liabilities (gains) or regulatory assets (losses). For contracts not subject to the ratemaking process only the difference between the accumulated unrealized net gains or losses recorded in prior periods and the cash proceeds are recognized in the income statement as nonoperating income. Prior to settlement, changes in the fair value of physical and financial forward sale and purchase contracts not subject to the ratemaking process are included in nonoperating income on a net basis. Unrealized mark-to-market gains and losses are included in the balance sheet as Risk Management Assets or Liabilities as appropriate.

For APCo, CSPCo and OPCo, depending on whether the delivery point for the electricity is in the traditional marketing area or not determines where the contract is reported in the income statement. Physical forward risk management sale and purchase contracts with delivery points in the traditional marketing area are included in revenues on a net basis. Prior to settlement, changes in the fair value of physical forward sale and purchase contracts in the traditional marketing area are also included in revenues on a net basis. Physical forward sale and purchase contracts for delivery outside of the traditional marketing area are included in nonoperating income when the contract settles. Prior to settlement, changes in the fair value of physical forward sale and purchase contracts with delivery points outside of the traditional marketing area are included in nonoperating income on a net basis.

Accounting for Derivative Instruments

For derivative contracts that are not designated as hedges or normal purchase and sale transactions, registrant subsidiaries recognize unrealized gains and losses prior to settlement based on changes in fair value during the period in our results of operations. When registrant subsidiaries settle mark-to-market derivative contracts and realize gains and losses, registrant subsidiaries reverse previously recorded unrealized gains and losses from mark-to-market valuations.

Registrant subsidiaries designate certain derivative instruments as hedges of forecasted transactions or future cash flows (cash flow hedges) or as a hedge of a recognized asset, liability or firm commitment (fair value hedge). Registrant subsidiaries report changes in the fair value of these instruments on our balance sheet. Registrant subsidiaries do not recognize changes in the fair value of the derivative instrument designated as a hedge in the current results of operations until earnings are impacted by the hedged item. Registrant subsidiaries also recognize any changes in the fair value of the hedging instrument, that are not offset by changes in the fair value of the hedged item, immediately in earnings.

Registrant subsidiaries measure the fair values of derivative instruments and hedge instruments accounted for using mark-to-market accounting based on exchange prices and broker quotes. If a quoted market price is not available, registrant subsidiaries estimate the fair value based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data, and other assumptions. Registrant subsidiaries reduce fair values by estimated valuation adjustments for items such as discounting, liquidity and credit quality. There are inherent risks related to the underlying assumptions in models used to fair value open long-term derivative contracts. Registrant subsidiaries have independent controls to evaluate the reasonableness of our valuation models. However, energy markets, especially electricity markets, are imperfect and volatile. Unforeseen events can and will cause reasonable price curves to differ from actual prices throughout a contract's term and at the time a contract settles. Therefore, there could be significant adverse or favorable effects on future results of operations and cash flows if market prices are not consistent with our approach at estimating current market consensus for forward prices in the current period. This is particularly true for long-term contracts.

Registrant subsidiaries recognize all derivative instruments at fair value in our balance sheets as either Risk Management Assets or Risk Management Liabilities. Registrant subsidiaries do not consider contracts that have been elected normal purchase or normal sale under SFAS 133 to be derivatives. Unrealized and realized gains and losses on all derivative instruments are ultimately included in revenues in the income statements on a net basis.

Long-Lived Assets

Long-lived assets are evaluated periodically for impairment whenever events or changes in circumstances indicate that the carrying amount of any such assets may not be recoverable. If the carrying amount is not recoverable, an impairment is recorded to the extent that the fair value of the asset is less then its book value.

Pension Benefits

AEP sponsors pension and other retirement plans in various forms covering all employees who meet eligibility requirements. AEP uses several statistical and other factors which attempt to anticipate future events in calculating the expense and liability related to its plans. These factors include assumptions about the discount rate, expected return on plan assets and rate of future compensation increases as estimated by management, within certain guidelines. In addition, AEP's actuarial consultants use subjective factors such as withdrawal and mortality rates to estimate these factors. The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates or longer or shorter life spans of participants. These differences may result in a significant impact to the amount of pension expense recorded. See "Pension Plans" in the Significant Factors section of Registrants' Combined Management's Discussion and Analysis for additional discussion.

New Accounting Pronouncements

Effective July 1, 2003, we implemented FIN 46, "Consolidation of Variable Interest Entities." As a result of the implementation, we consolidated two entities, Sabine Mining Company ($77.8 million) and JMG Funding, LP ($469.6 million), which were previously off-balance sheet. These entities were consolidated with SWEPCo and OPCo, respectively. There is no change in net income due to the consolidations. In addition, we deconsolidated the trusts which hold mandatorily redeemable trust preferred securities which were previously reported as Certain Subsidiary Obligated, Mandatorily Redeemable, Preferred Securities of Subsidiary Trusts Holding Solely Junior Subordinated Debentures of Such Subsidiaries ($321 million). As a result of the deconsolidation these amounts are now included in Long-term Debt. In December 2003, the FASB issued FIN 46R which replaces FIN 46. The

FASB and other accounting constituencies continue to interpret the application of FIN 46R. As a result, we are continuing to review the application of this new interpretation and expect to adopt FIN 46R by March 31, 2004.

See Notes 1 and 2 of the Notes to Respective Financial Statements for a discussion of significant accounting policies and additional impacts of new accounting pronouncements.

Other Matters

FERC Proposed Standard Market Design

In July 2002, the FERC issued its Standard Market Design (SMD) notice of proposed rulemaking, which sought to standardize the structure and operation of wholesale electricity markets across the country. Key elements of FERC's proposal included standard rules and processes for all users of the electricity transmission grid, new transmission rules and policies, and the creation of certain markets to be operated by independent administrators of the grid in all regions. The FERC issued a "white paper" on the proposal in April 2003, in response to the numerous comments that the FERC received on its proposal. Management does not know if or when the FERC will finalize a rule for SMD. Until any potential rule is finalized, management cannot predict its effect on cash flows and results of operations.

FERC Market Power Mitigation

A FERC order issued in November 2001 on AEP's triennial market based wholesale power rate authorization update required certain mitigation actions that AEP would need to take for sales/purchases within its control area and required AEP to post information on its website regarding its power system's status. As a result of a request for rehearing filed by AEP and other market participants, FERC issued an order delaying the effective date of the mitigation plan until after a planned technical conference on market power determination. In December 2003, the FERC issued a staff paper discussing alternatives and held a technical conference in January 2004. Management is unable to predict the timing of any further action by the FERC or its affect of future results of operations and cash flows.

Seasonality

The sale of electric power in AEP subsidiaries' service territories is generally a seasonal business. In many parts of the country, demand for power peaks during the hot summer months, with market prices also peaking at that time. In other areas, power demand peaks during the winter. The pattern of this fluctuation may change due to the nature and location of the AEP System's facilities and the terms of power contracts into which AEP enters. In addition, AEP subsidiaries have historically sold less power, and consequently earned less income, when weather conditions are milder. Unusually mild weather in the future could diminish results of operations and may impact cash flows and financial condition.

EXHIBIT 21

Subsidiaries of
American Electric Power Company, Inc.
As of December 31, 2003

The voting stock of each company shown indented is owned by the company immediately above which is not indented to the same degree. Subsidiaries not indented are directly owned by American Electric Power Company, Inc.

Name of Company	Location of Incorporation	Percentage of Voting Securities Owned By Immediate Parent	
American Electric Power Company, Inc.	New York		
American Electric Power Service Corporation	New York	100.0	
AEP C&I Company, LLC	Delaware	100.0	
AEP Coal, Inc.	Nevada	100.0	
AEP Communications, Inc.	Ohio	100.0	
AEP Energy Services, Inc.	Ohio	100.0	
AEP Generating Company	Ohio	100.0	
AEP Desert Sky LP, LLC	Delaware	100.0	
AEP Investments, Inc.	Ohio	100.0	
Mutual Energy L.L.C.	Delaware	100.0	
AEP Power Marketing, Inc.	Ohio	100.0	
AEP T&D Services, LLC	Delaware	100.0	
AEP Pro Serv, Inc.	Ohio	100.0	
AEP Texas POLR, LLC	Delaware	100.0	
AEP Resources, Inc.	Ohio	100.0	
Appalachian Power Company	Virginia	98.7	(a)
Cedar Coal Co.	West Virginia	100.0	
Central Appalachian Coal Company	West Virginia	100.0	
Central Coal Company	West Virginia	50.0	(b)
Southern Appalachian Coal Company	West Virginia	100.0	
Columbus Southern Power Company	Ohio	100.0	
Colomet, Inc.	Ohio	100.0	
Conesville Coal Preparation Company	Ohio	100.0	
Simco Inc.	Ohio	100.0	
Ohio Valley Electric Corporation	Ohio	4.3	(e)
Indiana-Kentucky Electric Corporation	Indiana	100.0	
Franklin Real Estate Company	Pennsylvania	100.0	
Indiana Michigan Power Company	Indiana	100.0	
Blackhawk Coal Company	Utah	100.0	
Price River Coal Company, Inc.	Indiana	100.0	
Kentucky Power Company	Kentucky	100.0	
Kingsport Power Company	Virginia	100.0	
Ohio Power Company	Ohio	99.2	(c)
Cardinal Operating Company	Ohio	50.0	(d)
Central Coal Company	West Virginia	50.0	(b)
Ohio Valley Electric Corporation	Ohio	39.9	(e)
Indiana-Kentucky Electric Corporation	Indiana	100.0	
Wheeling Power Company	West Virginia	100.0	
AEP Utilities, Inc.	Delaware	100.0	
AEP Texas Central Company	Texas	100.0	(f)
CPL Capital I	Delaware	100.0	
AEP Texas Central Transition Funding LLC	Delaware	100.0	(g)
Public Service Company of Oklahoma	Oklahoma	100.0	
PSO Capital I	Delaware	100.0	

Southwestern Electric Power Company	Delaware	100.0	
The Arklahoma Corporation	Arkansas	47.6	
SWEPCo Capital I	Delaware	100.0	
SWEPCo Capital Trust I	Delaware	100.0	(h)
Southwestern Arkansas Utilities Corporation	Arkansas	100.0	
Dolet Hills Lignite Company, LLC	Delaware	100.0	
AEP Texas North Company	Texas	100.0	(i)

Notes:

a. 13,499,500 shares of Common Stock, all owned by parent, have one vote each and 177,839 shares of Preferred Stock, all owned by the public, have one vote each.
b. Owned 50% by Appalachian Power Company and 50% by Ohio Power Company.
c. 27,952,473 shares of Common Stock, all owned by parent, have one vote each and 238,954 shares of Preferred Stock, all owned by the public, have one vote each.
d. Ohio Power Company owns 50% of the stock; the other 50% is owned by a corporation not affiliated with American Electric Power Company, Inc.
e. American Electric Power Company, Inc. and Columbus Southern Power Company own 39.9% and 4.3% of the stock, respectively, and the remaining 55.8% is owned by unaffiliated companies.
f. Central Power and Light Company changed its name to AEP Texas Central Company.
g. CPL Transition Funding LLC changed its name to AEP Texas Central Transition Funding LLC.
h. SWEPCo Capital Trust I was incorporated on August 15, 2003.
i. West Texas Utilities Company changed its name to AEP Texas North Company.

Exhibit 23

INDEPENDENT AUDITORS' CONSENT

We consent to the incorporation by reference in Registration Statement Nos. 333-46360, 333-39402, 333-66048 and 333-62278 of American Electric Power Company, Inc. on Form S-8, Post-Effective Amendment No. 1 to Registration Statement No. 333-50109 of American Electric Power Company, Inc. on Form S-8, Post-Effective Amendment No. 3 to Registration Statement No. 33-01052 of American Electric Power Company, Inc. on Form S-8, Post Effective Amendment No. 3 to Registration Statement No. 33-01734 of American Electric Power Company, Inc. on Form S-3, Pre-Effective Amendment No. 1 to Registration Statement No. 333-86050 of American Electric Power Company, Inc. on Form S-3, Registration Statement Nos. 333-105243 and 333-105532 of American Electric Power Company, Inc. on Form S-3, of our reports dated March 5, 2004 (which reports express unqualified opinions and include explanatory paragraphs concerning the adoption of new accounting pronouncements in 2002 and 2003), appearing in and incorporated by reference in this Annual Report on Form 10-K of American Electric Power Company, Inc. for the year ended December 31, 2003.

/s/ Deloitte & Touche LLP

Columbus, Ohio
March 10, 2004

Exhibit 24

POWER OF ATTORNEY

AMERICAN ELECTRIC POWER COMPANY, INC.
Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2003

The undersigned directors of AMERICAN ELECTRIC POWER COMPANY, INC., a New York corporation (the "Company"), do hereby constitute and appoint MICHAEL G. MORRIS, STEPHEN P. SMITH and SUSAN TOMASKY, and each of them, their attorneys-in-fact and agents, to execute for them, and in their names, and in any and all of their capacities, the Annual Report of the Company on Form 10-K, pursuant to Section 13 of the Securities Exchange Act of 1934, for the fiscal year ended December 31, 2003, and any and all amendments thereto, and to file the same, with all exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform every act and thing required or necessary to be done, as fully to all intents and purposes as the undersigned might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them, may lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, the undersigned have signed these presents this 28th day of January, 2004.

/s/ E. R. Brooks
E. R. Brooks

/s/ Donald M. Carlton
Donald M. Carlton

/s/ John P. DesBarres
John P. DesBarres

/s/ Robert W. Fri
Robert W. Fri

/s/ William R. Howell
William R. Howell

/s/ Lester A. Hudson, Jr.
Lester A. Hudson, Jr.

/s/ Leonard J. Kujawa
Leonard J. Kujawa

/s/ Michael G. Morris
Michael G. Morris

/s/ Richard L. Sandor
Richard L. Sandor

/s/ Thomas V. Shockley, III
Thomas V. Shockley, III

/s/ Donald G. Smith
Donald G. Smith

/s/ Linda Gillespie Stuntz
Linda Gillespie Stuntz

/s/ Kathryn D. Sullivan
Kathryn D. Sullivan

EXHIBIT 31(a)

CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, Michael G. Morris, certify that:

1. I have reviewed this annual report on Form 10-K of:

American Electric Power Company, Inc.
AEP Generating Company
AEP Texas Central Company
AEP Texas North Company
Appalachian Power Company
Columbus Southern Power Company
Indiana Michigan Power Company
Kentucky Power Company
Ohio Power Company
Public Service Company of Oklahoma
Southwestern Electric Power Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15e and 15d-15e) and internal controls over financial reporting (as defined in Exchange Act Rules 13a-15f and 15d-f), for the registrant and we have:

   a. designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluations; and

   c. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

   a. all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 10, 2004

By: /s/ Michael G. Morris

Chief Executive Officer

EXHIBIT 31(b)

CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, Susan Tomasky, certify that:

1. I have reviewed this annual report on Form 10-K of:

American Electric Power Company, Inc.
AEP Generating Company
AEP Texas Central Company
AEP Texas North Company
Appalachian Power Company
Columbus Southern Power Company
Indiana Michigan Power Company
Kentucky Power Company
Ohio Power Company
Public Service Company of Oklahoma
Southwestern Electric Power Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15e and 15d-15e) and internal controls over financial reporting (as defined in Exchange Act Rules 13a-15f and 15d-f), for the registrant and we have:

   a. designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluations; and

   c. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

   a. all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 10, 2004

By: /s/ Susan Tomasky

Chief Financial Officer

Exhibit 32.a

This Certificate is being furnished and shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63
Of Title 18 of the United States Code

In connection with the Annual Report of the Companies (as defined below) on Form 10-K (the "reports") for the year ended December 31, 2003 as filed with the Securities and Exchange Commission on the date hereof, I, Michael G. Morris, the chief executive officer of

American Electric Power Company, Inc.
AEP Generating Company
AEP Texas Central Company
AEP Texas North Company
Appalachian Power Company
Columbus Southern Power Company
Indiana Michigan Power Company
Kentucky Power Company
Ohio Power Company
Public Service Company of Oklahoma
Southwestern Electric Power Company

(the "Companies"), certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbarnes Oxley Act of 2002 that, based on my knowledge (i) the Reports fully comply with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Reports fairly presents, in all material respects, the financial condition and results of operations of the Companies.

/s/ Michael G. Morris
Michael G. Morris

March 10, 2004

A signed original of this written statement required by Section 906 has been provided to American Electric Power Company, Inc. and will be retained by American Electric Power Company, Inc. and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.b

This Certificate is being furnished and shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63
Of Title 18 of the United States Code

In connection with the Annual Report of the Companies (as defined below) on Form 10-K (the "reports") for the year ended December 31, 2003 as filed with the Securities and Exchange Commission on the date hereof, I, Susan Tomasky, the chief financial officer of

American Electric Power Company, Inc.
AEP Generating Company
AEP Texas Central Company
AEP Texas North Company
Appalachian Power Company
Columbus Southern Power Company
Indiana Michigan Power Company
Kentucky Power Company
Ohio Power Company
Public Service Company of Oklahoma
Southwestern Electric Power Company

(the "Companies"), certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbarnes Oxley Act of 2002 that, based on my knowledge (i) the Reports fully comply with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Reports fairly presents, in all material respects, the financial condition and results of operations of the Companies.

/s/ Susan Tomasky
Susan Tomasky

March 10, 2004

A signed original of this written statement required by Section 906 has been provided to American Electric Power Company, Inc. and will be retained by American Electric Power Company, Inc. and furnished to the Securities and Exchange Commission or its staff upon request.

Comprehensive Annual Financial Report

City of Austin, Texas

For the year ended
September 30, 2003

Prepared by:
Financial and Administrative Services Department

Vickie Schubert, CPA
Acting Director

Jeff Knodel, CPA
Controller

Members of the Government Finance Officers Association
of the United States and Canada

City Council

Will Wynn

Mayor

Term expires June 16, 2006

Jackie Goodman

Mayor Pro Tem

Term expires June 15, 2005

Council Members

Raul Alvarez	**June 16, 2006**
Betty Dunkerley	**June 15, 2005**
Brewster McCracken	**June 16, 2006**
Daryl Slusher	**June 15, 2005**
Danny Thomas	**June 16, 2006**

Toby Hammett Futrell

City Manager

CITY OF AUSTIN, TEXAS
COMPREHENSIVE ANNUAL FINANCIAL REPORT
Year Ended September 30, 2003

TABLE OF CONTENTS

	Exhibit	Page
INTRODUCTION		
Letter of Transmittal	–	i
City Organization Chart	–	vi
Certificate of Achievement	–	vii
FINANCIAL SECTION		
Independent Auditors' Report	–	1
Management's Discussion and Analysis (unaudited)	–	3
Basic Financial Statements		
Government-wide Financial Statements:		
Statement of Net Assets	A-1	16
Statement of Activities	A-2	18
Fund Financial Statements:		
Governmental Funds Balance Sheet	B-1	20
Reconciliation of the Governmental Funds Balance Sheet to the Statement of Net Assets	B-1.1	21
Governmental Funds Statement of Revenues, Expenditures and Changes in Fund Balances	B-2	22
Reconciliation of the Governmental Funds Statement of Revenues, Expenditures and Changes in Fund Balances to the Statement of Activities	B-2.1	23
Proprietary Funds Statement of Net Assets	C-1	24
Proprietary Funds Statement of Revenues, Expenses, and Changes in Fund Net Assets	C-2	28
Proprietary Funds Statement of Cash Flows	C-3	30
Fiduciary Funds Statement of Fiduciary Net Assets	D-1	36
Fiduciary Funds Statement of Changes in Fiduciary Net Assets	D-2	37
Notes to Basic Financial Statements:		
Note 1 Summary of Significant Accounting Policies	–	38
Note 2 Reconciliation of Government-wide and Fund Financial Statements	–	47
Note 3 Deficits in Fund Balance and Net Assets	–	49
Note 4 Pooled Investments and Cash	–	49
Note 5 Investments and Deposits	–	49
Note 6 Property Taxes	–	51
Note 7 Capital Assets and Infrastructure	–	52
Note 8 Retirement Plans	–	60
Note 9 Selected Revenues	–	63
Note 10 Debt and Non-Debt Liabilities	–	64
Note 11 Conduit Debt	–	82
Note 12 Interfund Balances and Transfers	–	82
Note 13 Litigation	–	83
Note 14 Commitments and Contingencies	–	83
Note 15 Other Post-Employment Benefits	–	89
Note 16 Subsequent Events	–	90
Required Supplementary Information (RSI) (unaudited)		
General Fund - Schedule of Revenues, Expenditures and Changes in Fund Balances - Budget and Actual-Budget Basis	RSI-1	92
Notes to Required Supplementary Information	–	93

CITY OF AUSTIN, TEXAS
COMPREHENSIVE ANNUAL FINANCIAL REPORT
Year Ended September 30, 2003

TABLE OF CONTENTS (continued)

	Exhibit	Page
FINANCIAL SECTION, Continued		
Combining and Fund Financial Statements and Schedules		
General Fund		
Schedule of Revenues - Budget and Actual-Budget Basis	E-1	95
Schedule of Expenditures - Budget and Actual-Budget Basis	E-2	96
Schedule of Transfers - Budget and Actual-Budget Basis	E-3	99
Nonmajor Governmental Funds		
Combining Balance Sheet	E-4	102
Combining Statement of Revenues, Expenditures, and Changes in Fund Balances	E-5	103
Special Revenue Funds		
Combining Balance Sheet	E-6	105
Combining Statement of Revenues, Expenditures and Changes in Fund Balances	E-7	106
Combining Balance Sheet - All Special Revenue Grants	E-8	107
Combining Statement of Revenues, Expenditures and Changes in Fund Balances – All Special Revenue Grants	E-9	108
Combining Schedule of Expenditures - All Special Revenue Grants	E-10	109
Other - Combining Balance Sheet	E-11	110
Other - Combining Statement of Revenues, Expenditures and Changes in Fund Balances	E-12	116
Other - Combining Schedule of Revenues, Expenditures and Transfers - Budget and Actual-Budget Basis	E-13	122
Debt Service Funds		
Combining Balance Sheet	E-14	128
Combining Statement of Revenues, Expenditures and Changes in Fund Balances	E-15	129
Combining Schedule of Revenues, Expenditures and Changes in Fund Balances - Budget and Actual-Budget Basis	E-16	130
Capital Projects Funds		
Balance Sheet	E-17	132
Statement of Revenues, Expenditures and Changes in Fund Balances	E-18	133
Combining Balance Sheet	E-19	134
Combining Statement of Revenues, Expenditures and Changes in Fund Balances	E-20	140
Permanent Funds		
Combining Balance Sheet	E-21	148
Combining Statement of Revenues, Expenditures and Changes in Fund Balances	E-22	149
Nonmajor Enterprise Funds		
Combining Statement of Net Assets	F-1	152
Combining Statement of Revenues, Expenses and Changes in Fund Net Assets	F-2	156
Combining Statement of Cash Flows	F-3	158
Internal Service Funds		
Combining Statements of Net Assets	G-1	164
Combining Statement of Revenues, Expenses and Changes in Fund Net Assets	G-2	168
Combining Statement of Cash Flows	G-3	170

CITY OF AUSTIN, TEXAS
COMPREHENSIVE ANNUAL FINANCIAL REPORT
Year Ended September 30, 2003

TABLE OF CONTENTS (continued)

	Exhibit	Page
FINANCIAL SECTION, Continued		
Fiduciary Funds		
Private-Purpose Trust Funds		
Combining Statement of Fiduciary Net Assets	H-1	175
Combining Statement of Changes in Fiduciary Net Assets	H-2	176
Agency Funds		
Combining Statement of Changes in Assets and Liabilities	H-3	177
Supplemental Schedules		
Enterprise Related Grants - Combining Balance Sheet	I-1	179
Enterprise Related Grants - Combining Schedule of Expenditures	I-2	180
Schedule of General Obligation Bonds Authorized and Unissued	I-3	181
Schedule of Revenue Bonds Authorized, Deauthorized and Unissued	I-4	182

STATISTICAL SECTION - UNAUDITED		
General Governmental Total Expenditures and Expenditures per Capita	1	186
General Obligation Net Debt and Net Debt per Capita	2	187
City of Austin Employees per Capita	3	188
Ratio of General Fund Unreserved Ending Balance to General Governmental Annual Expenditures	4	189

	Table	Page
General Governmental Expenditures by Function	1	190
General Governmental Expenditures by Function (Constant Dollars)	2	192
General Fund Revenues and Other Financing Sources by Source	3	193
Assessed Valuation, Estimated Market Value, Tax Rates, Tax Levies, and Tax Collections	4	194
Principal Taxpayers	5	195
Ratio of Net General Bonded Debt to Assessed Value and Net Bonded Debt per Capita	6	196
Ratio of Annual Debt Service Expenditures for General Bonded Debt to Total General Fund Expenditures	7	197
Computation of Legal Debt Margin	8	198
Computation of Direct and Overlapping Debt	9	199
Property Tax Rates and Tax Levies for Direct and Overlapping Governments with Applicable Percentages Over 10%	10	200
City Sales Tax - Tax Levied Effective January 1, 1968	11	201
Electric Fund and Water and Wastewater Fund - Miscellaneous Statistics	12	202
Electric Fund and Water and Wastewater Fund - Five-Year Comparative Operating Schedule	13	203
Electric Fund and Water and Wastewater Fund - Plant Cost and Equity in Utility Systems	14	205
Schedule of Combined Utility Systems Revenue Bond Coverage	15	206
Transfers from Electric Fund and Water and Wastewater Fund to General Fund	16	207
Electric Fund and Water and Wastewater Fund - Statistical Data	17	208
Water and Wastewater Fund - Large Customers	18	209
Airport Enplaned and Deplaned Statistics	19	210
Schedule of Insurance in Force	20	211
Hotel-Motel Occupancy Tax - Tax Levied Effective January 1, 1971	21	213
Vehicle Rental Tax – Tax Levied Effective January 1, 1999	22	214
Miscellaneous Statistical Data	23	215
Miscellaneous Statistical Data - Economic and Growth Indicators	24	216
Miscellaneous Statistical Data - Employment Characteristics	25	217
Elements of Budget Fund Balance for Selected Operating Funds	26	218

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INTRODUCTION

City of Austin
Municipal Building 124 West 8th St., P.O. Box 1088, Austin, Texas 78767

March 26, 2004

Honorable Mayor and Council Members
City of Austin, Texas

Ladies and Gentlemen:

We are pleased to submit to you the 2003 Comprehensive Annual Financial Report (CAFR) of the City of Austin, Texas. The report was prepared by the Financial and Administrative Services Department, Controller's Office. The combined financial statements and related notes have been jointly audited by the independent firms of Certified Public Accountants, KPMG LLP, and R. Mendoza & Company, P.C., whose reports are included herein. This audit satisfies Article VII, Section 16 of the City Charter, which requires an annual audit of all accounts of the City by an independent Certified Public Accountant. The Federal awards received by the City directly from Federal agencies or passed through by the State of Texas or other governmental entities during fiscal year 2003 are being audited under the provisions of the Single Audit Act of 1996, as amended, and State awards are being audited under the provisions of the *State of Texas Single Audit Circular*. The reports will be available in the City's separately issued Single Audit Report.

Responsibility for both the accuracy of the presented data and the completeness and fairness of the presentations, including all disclosures, rests with the City. We believe the data, as presented, are accurate in all material respects and are presented in a manner which fairly sets forth the financial position and results of operations of the City. Furthermore, we believe all disclosures necessary to enable the reader to gain an understanding of the City's financial activity have been included.

These financial statements have been prepared in accordance with generally accepted accounting principles (GAAP) for local governments as prescribed by the Governmental Accounting Standards Board (GASB) and the American Institute of Certified Public Accountants (AICPA).

GASB Statement No. 34, entitled *"Basic Financial Statements – and Management's Discussion and Analysis – for State and Local Governments"* requires that management provide a narrative introduction, overview and analysis to accompany the Basic Financial Statements in the form of management discussion and analysis (MD&A). This letter of transmittal is intended to complement MD&A and should be read in conjunction with it. The MD&A can be found immediately following the Independent Auditor's Report.

REPORTING ENTITY

This CAFR includes the financial activities of the primary government and its component units. The City provides a full range of services, including general government, public safety, transportation, planning and sustainability, public health, public recreation and culture, urban growth management, electric, water and wastewater, airport and other enterprise services. In addition, the City has blended with its financial statements those of the separate legal entities, the Austin Housing Finance Corporation, whose activities are reported in the Housing Assistance Fund, and the Austin Industrial Development Corporation, whose activities are included in the Austin Industrial Development Corporation Fund.

AUSTIN'S GOVERNMENT, ECONOMY AND OUTLOOK

The City of Austin, chartered in 1839, has a Council-Manager form of government with a Mayor and six Councilmembers. The Mayor and Councilmembers are elected at large for three-year staggered terms with a maximum of two consecutive terms. A petition signed by a minimum 5 percent of voters waives the term limit for a councilmember. The City Manager, appointed by the City Council, is responsible to them for the management of all City employees and the administration of all City affairs.

Austin, the capital of the state of Texas, is the fourth largest city in Texas (behind Houston, Dallas, and San Antonio), with a year 2000 population of 656,562. According to the 2000 Census, Austin's population grew since 1990 by 191,000 residents, which represents an increase of 41 percent. Geographically, Austin consists of approximately 275 square miles. Austin has a median household income of $42,689 and a per capita income of $24,163.

Austin is frequently recognized as a great place to live and/or work, with one of the most recent commendations in *Forbes*, which rated Austin as the number one city on its list of Best Places for Business and Careers. *Forbes* also recognized Austin as the best city for singles. Austin has long attracted a variety of people, and the reasons that draw people to the City are varied. The area has a natural beauty and a first-rate parks department that administers a number of public outdoor recreational facilities, including neighborhood parks, greenbelts, athletic fields, golf courses, tennis courts, a veloway for bicyclists and in-line skaters, miles of hike and bike trails and striped bike lanes, a youth entertainment complex and swimming pools.

Residents of Austin enjoy many outdoor events, including art, music, and food and wine festivals; races and bicycle rides; and the nightly flights of the world's largest urban bat colony. Indoor events vary from music to museums to ice hockey, art galleries, an opera facility and a wide variety of restaurants and clubs. Long recognized as the "live music capital of the world," Austin boasts more than 100 live music venues, and is home to the annual South by Southwest (SXSW) music, film and interactive festivals each spring as well as the Austin City Limits Festival each fall.

The educational opportunities in Austin have long drawn people to the city. Among U.S. cities with a population over 250,000, Austin is one of the most highly educated cities, with more than 30 percent of its adults having a college degree and over 88 percent of the workforce having some college education. With its seven institutions of higher learning and more than 94,000 students, education is a significant aspect of life in the Austin area. The University of Texas at Austin (UT), the largest public university in the nation, is known as a world-class center of education and research.

During the 1990s, over 280,000 jobs were created in Austin; unemployment dropped to less than 2 percent in 2000. Since then, Austin and the Central Texas area have been hit hard by the technology slump. Although the Austin area unemployment rate has improved slightly from the previous year, it remains significantly higher than prior to the economic downturn. The unemployment rate for September 2003 was 5.5 percent, which is a slight improvement from the September 2002 rate of 5.7 percent. Statewide, the unemployment rate stands at 6.6 percent, compared to 6.5 percent a year ago.

Layoffs and the nationwide slump in tourism have negatively impacted both sales tax and hotel tax revenues from levels experienced a few years ago. While, hotel tax revenues increased by 3 percent from the prior year, they are still below pre-9/11 levels. During 2003, sales tax revenue declined 4.5 percent. Early 2004 collections show an increase in sales tax and hotel bed taxes, which may indicate that the economic slump is beginning to improve. Property taxes for 2003 and subsequent years may be negatively impacted by lawsuits filed against the appraisal district; the suits challenge the appraisal district's property valuations for many businesses. If the challenges are successful, they could result in decreased tax revenue next year for the local taxing jurisdictions, including the City. These financial statements include the impact of estimated refunds for the pending lawsuits.

The City's airport continues to see a decline in travel as a result of the 9/11 tragedy and continued security concerns related to air travel. Total airline passengers declined slightly in 2003 from the previous year. Costs related to the operations of the airport increased significantly due to security costs. Parking revenues have also declined significantly due to the decline in travel and an increase in competition from other parking sites located near the airport. The City's Convention Center facilities, with the addition of the expanded Convention Center facility and the new Palmer Events Center, increased revenues significantly from the previous year. The increase in revenues was proportionately higher than the increase in expenses to operate the facilities, in part due to cost-cutting initiatives instituted beginning in 2002. Although water and wastewater revenues were higher than the previous year, they were less than anticipated due to mild weather conditions.

City management implemented cost savings efforts beginning in 2002 and throughout the 2003 budget. During the 2003 budget development, a structural budget process was instituted. As part of this process, an emphasis was placed on funding the City's expenditures with on-going revenue sources instead of relying on one-time revenue occurrences and excess ending balances in order to balance the budget. Aside from public safety related costs, significant cost reductions occurred across the City, primarily in the General and Support Services Funds. As part of the 2003 budget, over 300 vacant positions were

cut from the budget. Economic indicators show that the economy is beginning to improve in early 2004; however, the City continues to be extremely cautious regarding future economic projections.

For the future, Austin's strengths continue to be the ones that led to growth in the recent past: a highly capable workforce, innovation and entrepreneurship, clusters in knowledge industries, the presence of a world-class research university and several other institutions of higher learning, strong community assets and a superior quality of life. Austin has recently reorganized its economic development activity to focus on three major areas: traditional economic development (including primary employers), small business development, and cultural vitality.

MAJOR INITIATIVES AND ACHIEVEMENTS

The City has a number of significant initiatives underway or recently completed, as described below. These initiatives should have a positive effect on the City's economic health and services to residents and businesses.

Health and Safety Projects

Brackenridge Hospital is operated by the Daughters of Charity under a lease agreement with the City. In order to accommodate certain ethical religious directives, Seton and the City agreed to construct a separately licensed facility for reproductive services and to increase maternity capacity. In February 2004, construction of the Austin Women's Hospital was completed. The facility, which is located on the fifth floor of Brackenridge Hospital, will be operated by the University of Texas Medical Branch at Galveston. The new hospital will maintain access for anyone in need of reproductive health care services; maintain seamless delivery of services; and maintain the high quality of care available at Brackenridge Hospital. The facility is expected to open in March 2004.

The City, Travis County and local leaders are developing a plan for a health care district for Austin/Travis County. Such a district would allow for the creation of a dedicated funding source for the provision of indigent health care costs to all residents in Austin and Travis County. In order for the health care district to be created, an election within Travis County is required. It is anticipated that the election will occur in May 2004.

Construction of the Combined Transportation, Emergency and Communication Center was completed in October 2003. The facility supports existing and new operations of critical emergency communications and transportation management for the region. It is located at the former site of the Robert Mueller Airport.

Convention and Cultural Projects

The City operates the Austin Convention Center, in addition to the Palmer Events Center. In June 2002, construction was completed for the expansion of the Convention Center, which effectively doubled the size of the facility. On January 5, 2004, the new Convention Center Headquarters Hotel, which is adjacent to the Convention Center, opened for business. This hotel is owned by Austin Convention Enterprises, Inc., and operated by Hilton Hotels Corporation. The Palmer Events Center is located next to Town Lake and is utilized for arts and crafts shows, concerts, trade shows and small conventions.

The City continues with building a new City Hall and Public Plaza, which will be one of Austin's newest landmarks. The City Hall will overlook lovely Town Lake. December 2, 2003 marked the topping-out ceremony, which approximates the halfway point in construction of the building and plaza. Construction is expected to be completed in the Fall of 2004.

Economic Development and Transportation Projects

A vital, on-going project is the redevelopment of the former Robert Mueller Municipal Airport (RMMA) site. The 709-acre site is envisioned as a transit-oriented community, including a town square, a mixed-use district, an employment center, a variety of residential uses, and the site of a new children's hospital. The City selected Catellus Development Corporation as the developer for this long-term project and is currently negotiating the elements of the development agreement for the property.

The City is continuing work on transportation projects approved by the voters in 2000. Projects include improvements to State Highway (SH) 183, which will improve access to Austin-Bergstrom International Airport; extension of Loop 1 North; construction of an east-west highway SH 45N in the northern portion of Travis County; and SH 130, which will provide an alternative to IH 35 to the east of the City. Other projects include improved transportation options for pedestrians and bicyclists.

Utility Projects

Austin Energy, the City's electric utility, continues its efforts to remain competitive in the new deregulated environment. Deregulation allows Texas residents and businesses served by utilities participating in deregulation to choose the supplier from which they purchase their electricity. The local electric utility continues to deliver the electricity. Deregulation began in Texas on January 1, 2002 for all private electric utilities. These utilities, owned by stockholders, are called investor-owned utilities (IOUs). Electric cooperatives (Co-ops) and city-owned electric utilities (called municipally owned utilities or MOUs) such as Austin Energy can participate, or "opt-in," by a vote of their board or City Council. Once the City Council votes to

participate in deregulation, it cannot later withdraw. The City has not "opted-in", but does continue to prepare for that possibility. A key step in remaining competitive was to begin moving from issuing combined utility debt (combined electric and water and wastewater) to issuing debt specific to the electric utility. To proceed towards that goal, Austin Energy issued $182.1 million in Electric Utility revenue refunding bonds and refunded $100.3 million of the Combined Utility System tax exempt commercial paper and $87 million of the outstanding Combined Utility System taxable commercial paper during 2003. Austin Energy continues to increase participation in the GreenChoice Program, including participation from Concordia University, which is the first college in the nation to subscribe to 100 percent green power. Austin Energy's GreenChoice Program ranks number one in the nation in green power sales according to the Department of Energy.

The Water and Wastewater Utility has launched the Austin Clean Water Program. The Program is the result of a mandate from the U.S. Environmental Protection Agency to eliminate overflows from its wastewater collection system by the end of 2007. The cost to complete this program is estimated to be $150 million. The Utility reduced its debt liability by issuing refunding bonds during the year. Consent obtained from Utility bondholders to replace a debt service fund with a surety bond will result in releasing cash reserves that may be used to defease outstanding debt.

Status of City Services
The vision of the City of Austin is to be the most livable community in the country. To achieve this vision, the governing leaders of the City invite citizens to participate in the Citizen Satisfaction Survey. The City has conducted the survey since 1997.

Police, EMS, and Fire are the three highest rated services in the survey. The top issues of importance to Austin residents are:
- Downtown issues (parking, traffic, construction)
- Tax related issues (including utility rates, fees and charges)
- Road conditions/new roads
- Growth management
- Jobs

The City is committed to incorporating the public's preferences into its strategic planning and use the public's expression of satisfaction as a criterion of accountability.

OTHER

Internal Controls and Budgetary Control
City management is responsible for establishing, implementing and maintaining a framework of internal controls designed to ensure that City assets are protected from loss, theft or misuse, and to ensure that adequate accounting data is compiled to allow for the preparation of financial statements in conformity with Generally Accepted Accounting Principles (GAAP). The system of internal control is designed to provide reasonable, but not absolute, assurance that these objectives are met. The concept of reasonable assurance recognizes that: 1) the cost of control should not exceed the benefits likely to be derived; and 2) the evaluation of costs and benefits requires estimates and judgments by management. All internal control evaluations occur within this framework and are believed to adequately safeguard assets and provide reasonable assurance of proper recording of financial transactions. The City employs a computerized financial accounting system that includes a system of internal accounting controls.

The Financial and Administrative Services Department is responsible for providing all centralized City financial services including financial accounting, reporting and budgeting, payroll and accounts payable disbursement functions, cash and investment management, debt management, and purchasing and contract administration. The Director of Financial Services, appointed by the City Manager, supervises the department's operations.

The objective of budgetary controls is to ensure compliance with legal provisions in the annual appropriated budget approved by the City Council. The annual operating budget, or financial plan, is proposed by the City Manager and enacted by the City Council after public discussion. Subsequent intradepartmental budget transfers must be approved by the City Manager. Interdepartmental transfers and any increase or decrease in total appropriations must be approved by the City Council. Management control for the operating budget is maintained at the fund and department level.

Primary responsibility for fiscal analysis of budget to actual expense or revenue and overall program fiscal standing rests with the department operating the program. As demonstrated by the statements and schedules included in the City's 2003 Comprehensive Annual Financial Report, the City continues to meet its responsibility for sound financial management.

Cash Management
The City's investment policy is to minimize credit and market risk while maintaining a competitive portfolio yield. Cash balances of all City funds are invested in consideration of five factors: safety, term, liquidity, market exposure and rate of return. Cash balances of most funds, except the debt service and revenue bond retirement reserve, are pooled for investment

purposes. These investments are made in accordance with the Texas Public Funds Investment Act and the City of Austin Investment Policy. During 2003, the City's cash resources were primarily invested in U.S. Treasury and Agency issues. The average yield on pooled investments during the year was 2.46 percent, and the weighted average maturity of the investments was 363 days.

Risk Management

The City maintains three internal service funds to account for its risk of loss associated with torts and employee and workers' compensation benefits. The City continues to be self-insured for liabilities for most health benefits, third-party claims, and workers' compensation. The City purchases commercial insurance for coverage for property loss or damage, commercial crime, fidelity bonds and airport operations. In addition, the City purchases a broad range of insurance coverage for contractors working at selected capital improvement project sites. The City does not participate in a risk pool. Liabilities are reported when it is probable that a loss has been incurred at the date of the financial statements and the amount of the loss can be reasonably estimated. Liabilities include an amount for claims that have been incurred but not reported (IBNR). Claim liabilities for the Employee Benefits Fund and the Workers' Compensation Fund are calculated based on outstanding claims and actuarial data; the Liability Reserve Fund is based on outstanding claims.

CERTIFICATE OF ACHIEVEMENT

The Government Finance Officers Association of the United States and Canada (GFOA) awarded a Certificate of Achievement for Excellence in Financial Reporting to the City for its 2002 Comprehensive Annual Financial Report (CAFR). This is the eleventh consecutive year that the City has achieved this prestigious award. A Certificate of Achievement is valid for a period of one year only. City management believes that this 2003 CAFR conforms to the Certificate of Achievement Program requirements, and we are submitting it to GFOA for its review.

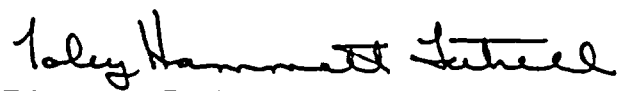
ACKNOWLEDGMENTS

The preparation of this report on a timely basis could not have been accomplished without the dedicated services of a highly qualified staff. The City of Austin has such a staff in the Controller's Office of the Financial and Administrative Services Department. We would like to express our appreciation to all the staff of the Controller's Office who assisted in and contributed to the preparation of this report.

Other departments and offices of the City have also contributed directly or indirectly to the preparation of this report. In particular, the Budget Office of the Financial and Administrative Services Department and the Office of the City Auditor have been instrumental in ensuring that good financial management practices are maintained, and their cooperation and continued assistance is appreciated. We also acknowledge the efforts of the City departments in following good financial management practices and in providing information and assistance during the preparation of the report.

We acknowledge the thorough, professional and timely manner in which our independent auditors, KPMG LLP and R. Mendoza & Company, P.C., conducted the audit.

Finally, we acknowledge the Mayor and Council Members who have consistently supported the City's goal of excellence in all aspects of financial management. Their support is greatly appreciated.

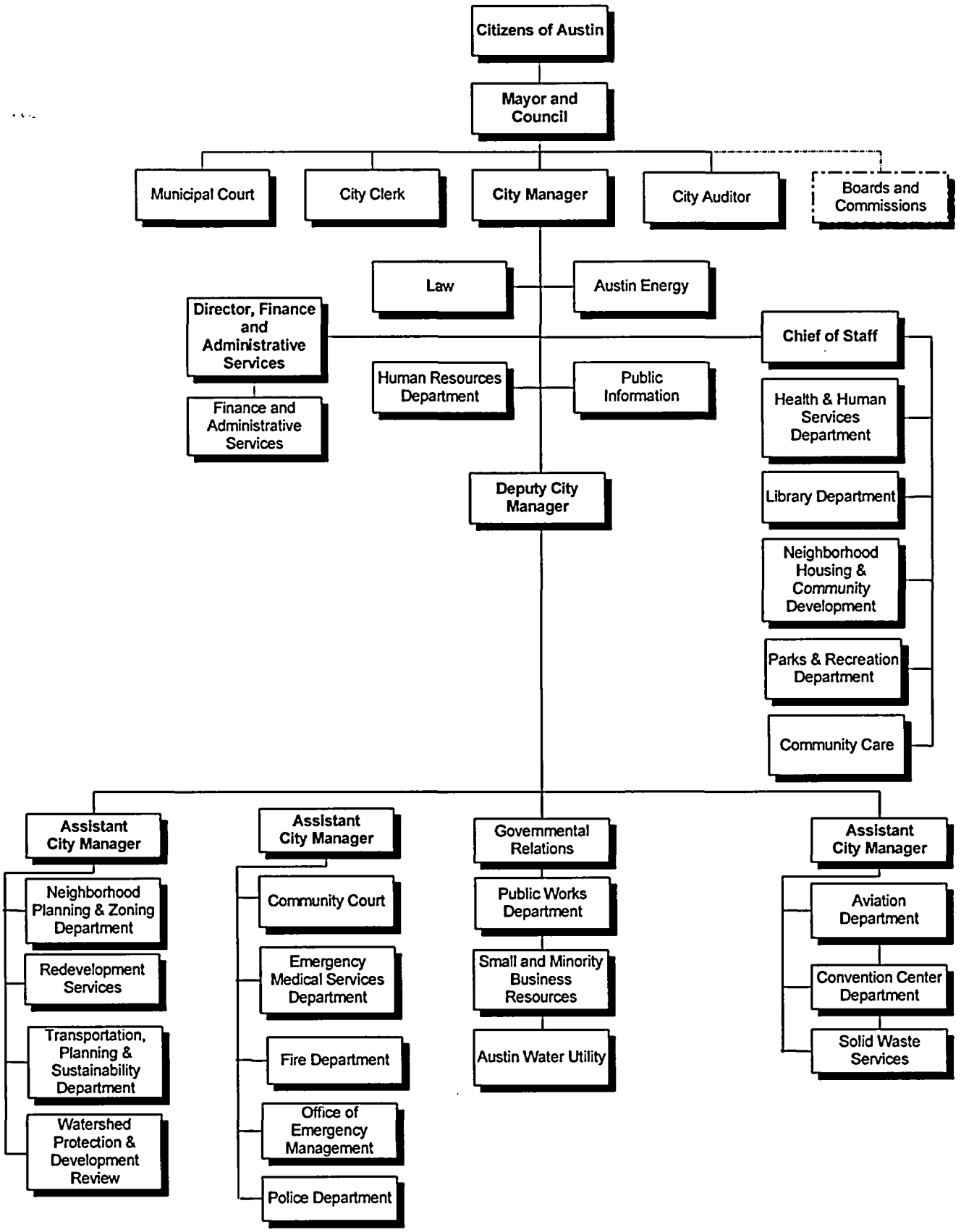


Toby Hammett Futrell
City Manager

Vickie Schubert, CPA
Acting Director, Financial and Administrative Services Department

City of Austin, Texas

ORGANIZATIONAL CHART



The Government Finance Officers Association of the United States and Canada (GFOA) awarded a Certificate of Achievement for Excellence in Financial Reporting to the City of Austin, Texas for its Comprehensive Annual Financial Report for the Fiscal Year Ended September 30, 2002.

In order to be awarded a Certificate of Achievement, a governmental unit must publish an easily readable and efficiently organized Comprehensive Annual Financial Report, whose contents conform to program standards. Such reports must satisfy both generally accepted accounting principles and applicable legal requirements. A Certificate of Achievement is valid for a period of one year only. City management believes that this 2003 CAFR conforms to the Certificate of Achievement Program requirements, and we are submitting it to GFOA for their review.

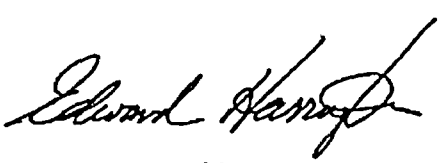
Certificate of Achievement for Excellence in Financial Reporting

Presented to

City of Austin, Texas

For its Comprehensive Annual Financial Report for the Fiscal Year Ended September 30, 2002

A Certificate of Achievement for Excellence in Financial Reporting is presented by the Government Finance Officers Association of the United States and Canada to government units and public employee retirement systems whose comprehensive annual financial reports (CAFRs) achieve the highest standards in government accounting and financial reporting.



President

Executive Director

CITY OF AUSTIN
FOUNDED 1839

FINANCIAL SECTION

KPMG LLP
Suite 1100
111 Congress Avenue
Austin, TX 78701

R. Mendoza & Company, P.C.
Certified Public Accountants
2211 South I.H.35, Suite 410
Austin, TX 78741

INDEPENDENT AUDITORS' REPORT

The Honorable Mayor and
Members of the City Council,
City of Austin, Texas:

We have audited the accompanying financial statements of the governmental activities, the business-type activities, each major fund, and the aggregate remaining fund information of the City of Austin, Texas ("City"), as of and for the year ended September 30, 2003, which collectively comprise the City's basic financial statements as listed in the table of contents under "Basic Financial Statements". These financial statements are the responsibility of the City's management. Our responsibility is to express opinions on these financial statements based on our audit.

We conducted our audit in accordance with auditing standards generally accepted in the United States of America and the standards applicable to financial audits contained in *Government Auditing Standards*, issued by the Comptroller General of the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinions.

In our opinion, the financial statements referred to above present fairly, in all material respects, the respective financial position of the governmental activities, the business-type activities, each major fund, and the aggregate remaining fund information of the City, as of September 30, 2003, and the respective changes in financial position and cash flows, where applicable, thereof for the year then ended in conformity with accounting principles generally accepted in the United States of America.

The Management's Discussion and Analysis on pages 3 through 14 and the General Fund Schedule of Revenues, Expenditures and Changes in Fund Balances – Budget and Actual – Budget Basis on pages 94 through 95 are not a required part of the basic financial statements but are supplementary information required by accounting principles generally accepted in the United States of America. We have applied certain limited procedures, which consisted principally of inquiries of management regarding the methods of measurement and presentation of the required supplementary information. However, we did not audit the information and express no opinion on it.

In accordance with *Government Auditing Standards*, we have also issued a report dated February 6, 2004 on our consideration of the City's internal control over financial reporting and our tests of its compliance with certain provisions of laws, regulations, contracts, and grants. That report is an integral part of an audit performed in accordance with *Government Auditing Standards* and should be read in conjunction with this report in considering the results of our audit.

Our audit was conducted for the purpose of forming opinions on the financial statements that collectively comprise the City's basic financial statements. The accompanying introduction, combining and fund financial statements and schedules, supplemental schedules, and statistical section are presented for purposes of additional analysis and are not a required part of the basic financial statements. The combining and fund financial statements and schedules, and supplemental schedules have been subjected to the auditing procedures applied in the audit of the basic financial statements and, in our opinion, are fairly stated in all material respects in relation to the basic financial statements taken as a whole. The introduction and statistical section have not been subjected to the auditing procedures applied in the audit of the basic financial statements and, accordingly, we express no opinion on them.

KPMG LLP

R. Mendoza & Company, P.C.

Austin, Texas
February 6, 2004

KPMG LLP, a U.S. limited liability partnership, is the U.S. member firm of KPMG International, a Swiss cooperative

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The Management's Discussion and Analysis (MD&A) section of the City of Austin's (the City) Comprehensive Annual Financial Report presents a narrative overview and analysis of the financial activities of the City for the fiscal year ended September 30, 2003. We encourage readers to consider the information presented here in conjunction with additional information that we have furnished in our letter of transmittal.

The financial statements are presented in conformance with the Governmental Accounting Standards Board Statement No. 1 through Statement No. 39 and Statement 41. During the current fiscal year, the City implemented GASB Statement No. 39, *"Determining if Certain Organizations are Component Units"* and GASB Statement No. 41, *"Budgetary Comparison Schedules – Perspective Differences – an amendment to GASB Statement No. 34"*. These statements did not alter the City's financial reporting presentation from previous years.

FINANCIAL HIGHLIGHTS

The assets of the City exceeded its liabilities at the close of the most recent fiscal year by $3.6 billion (net assets). Of this amount, unrestricted net assets of $618 million may be used to meet the City's ongoing obligations to citizens and creditors.

Total net assets for the City of Austin increased by $241.4 million during the fiscal year.

As of September 30, 2003, the City's governmental activities reported combined net asset balances of $1.3 billion. Approximately 3% of this total amount, or $43 million, represents unrestricted net assets available for spending at the City's discretion.

At the close of the current fiscal year, unreserved fund balance for the General Fund was $88 million or 20% of total General Fund expenditures of $433 million.

The City's total noncurrent liabilities increased $14 million during the current fiscal year. Governmental noncurrent liabilities increased $22 million and business-type noncurrent liabilities decreased $8 million; business-type obligations are self-supporting, and do not rely on tax revenues for repayment. The key factors in this increase included issuance of new debt, which was partially offset by principal payment or refunding of existing debt.

OVERVIEW OF THE FINANCIAL STATEMENTS

This discussion and analysis is intended to serve as an introduction to the City's basic financial statements, consisting of three components:

- government-wide financial statements,
- fund financial statements and
- notes to the financial statements.

This report also contains other supplementary information in addition to the basic financial statements, including information on individual funds.

a – Government-wide Financial Statements

The government-wide financial statements are designed to provide readers with a broad overview of the City's finances, in a manner comparable to a private-sector business. The two government-wide financial statements are, as follows:

- The ***statement of net assets*** presents information on all of the City's assets and liabilities, with the difference between the two reported as net assets. Over time, increases or decreases in net assets may serve as a useful indicator of whether the financial position of the City of Austin is improving or deteriorating.

- The ***statement of activities*** presents information showing how the City's net assets changed during the most recent fiscal year. All changes in net assets are reported as soon as the underlying event giving rise to the change occurs, regardless of the timing of related cash flows. Thus, revenues and expenses are reported in this statement for some items that will only result in cash flows in future fiscal periods, such as revenues pertaining to uncollected taxes and expenses pertaining to future general obligation debt payments. The statement includes the annual depreciation for infrastructure and governmental assets.

OVERVIEW OF THE FINANCIAL STATEMENTS, continued

Both of the government-wide financial statements distinguish functions of the City that are principally supported by taxes and intergovernmental revenues (governmental activities) from other functions that are intended to recover all or a significant portion of their costs through user fees and charges (business-type activities). The governmental activities of the City include general government; public safety; transportation, planning and sustainability; public health; public recreation and culture; and urban growth management. The business-type activities of the City include electric utility, water and wastewater utility, airport, convention and others.

The government-wide financial statements include the City as well as blended component units: the Austin Housing Finance Corporation (AHFC) and the Austin Industrial Development Corporation (AIDC). The operations of AHFC and AIDC are included within the governmental activities of the government-wide financial statements. AHFC is reported as the Housing Assistance Fund. Although legally separate from the City, these component units are blended with the City because of their governance or financial relationships to the City.

b -- Fund Financial Statements
The fund financial statements are designed to report information about groupings of related accounts which are used to maintain control over resources that have been segregated for specific activities or objectives. The City, like other state and local governments, uses fund accounting to ensure and demonstrate compliance with finance-related legal requirements. All of the funds of the City can be divided into the following three categories: governmental, proprietary and fiduciary funds. Within the governmental and proprietary categories, the emphasis is on the major funds.

Governmental funds. Governmental funds are used to account for essentially the same functions reported as governmental activities in the government-wide financial statements. Most of the City's basic services are reported in governmental funds, which focus on how cash and other financial assets can readily be converted to available resources and on the available balances left at year-end. This information may be useful in determining what financial resources are available in the near future to finance the City's programs. Other funds are referred to as nonmajor funds and are presented as summary data.

Because the focus of governmental fund level statements is narrower than that of the government-wide financial statements, it is useful to compare the information presented for governmental funds with similar information presented in the government-wide statements. In addition to the governmental fund balance sheet and statement of revenues, expenditures and changes in fund balance, separate statements are provided that reconcile between the government-wide and fund level statements.

The City's General Fund is considered a major fund and information is presented separately in the governmental fund balance sheet and statement of revenues, expenditures and changes in fund balances. In addition, the City maintains several individual governmental funds organized according to their type (special revenue, debt service, capital projects and permanent funds). Data from these governmental funds are combined into a single column labeled nonmajor governmental funds. Individual fund data for the funds are provided in the form of combining statements in the supplementary section of this report.

Proprietary funds. Proprietary funds are generally used to account for services for which the City charges customers —either outside customers or internal units or departments of the City. Proprietary fund statements provide the same type of information as shown in the government-wide financial statements, only in more detail. The City maintains the following two types of proprietary funds:

- Enterprise funds are used to report the same functions presented as business-type activities in the government-wide financial statements. The City uses enterprise funds to account for the operations of the City's three major funds, Electric, Water and Wastewater and Austin-Bergstrom International Airport (Airport), as well as the nonmajor enterprise funds.

- Internal Service funds are used to report activities that provide supplies and services for many City programs and activities. The City uses internal service funds to account for Capital Projects Management, Employee Benefits, Fleet Maintenance, Information Systems, Liability Reserve, Support Services, Wireless Communication and Workers' Compensation. Because these services benefit governmental operations more than business-type functions, they have been included in governmental activities in the government-wide financial statements.

The nonmajor enterprise funds and the internal service funds are combined into two aggregated presentations in the proprietary fund financial statements. Individual fund data for the funds are provided in the form of combining statements in the supplementary section of this report.

OVERVIEW OF THE FINANCIAL STATEMENTS, continued

Fiduciary funds. Fiduciary funds are used to account for resources held for the benefit of parties outside the City. Since the resources of fiduciary funds are not available to support the City's own programs, they are not reflected in the government-wide financial statements. The accounting policies applied to fiduciary funds is much like those used for proprietary funds.

Comparison of Government-wide and Fund Financial Components. The following chart compares how the City's funds are included in the government-wide and fund financial statements:

Fund Types / Other	Government-wide	Fund Financials
General Fund	Governmental	Governmental
Special revenue funds	Governmental	Governmental - Nonmajor
Debt service funds	Governmental	Governmental - Nonmajor
Capital project funds	Governmental	Governmental - Nonmajor
Permanent funds	Governmental	Governmental - Nonmajor
Internal service funds	Governmental	Proprietary
Assets previously reported in General Fixed Asset Group	Governmental	Excluded
Infrastructure assets	Governmental	Excluded
Liabilities previously reported in General Long-Term Debt Group	Governmental	Excluded
Electric	Business-type	Proprietary
Water and wastewater	Business-type	Proprietary
Airport	Business-type	Proprietary
Other enterprise funds	Business-type	Proprietary - Nonmajor
Fiduciary funds	Excluded	Fiduciary

Basis of Reporting - The government-wide statements and fund-level proprietary statements are reported using the flow of economic resources measurement focus and the full accrual basis of accounting. The governmental fund financial statements are reported using the current financial resources measurement focus and the modified accrual basis of accounting.

c -- Notes to the Financial Statements
The notes to the financial statements provide additional information that is essential to a full understanding of the data provided in the government-wide and fund financial statements.

d -- Other Information
The section Required Supplementary Information (RSI) immediately follows the basic financial statements section of this report. The City adopts an annual appropriated budget for the General Fund. The RSI provides a comparison to budget and demonstrates budgetary compliance. Following the RSI are other statements and schedules, including the combining statements for nonmajor governmental and enterprise funds, internal service funds and fiduciary funds.

FINANCIAL ANALYSIS OF THE GOVERNMENT-WIDE STATEMENTS

a – Net Assets

The following table reflects a summary of Net Assets compared to prior year (in thousands):

Net Assets
as of September 30
(in thousands)

	Governmental Activities		Business-Type Activities (1)		Total	
	2003	2002	2003	2002	2003	2002
Current assets	$ 529,203	575,751	1,073,730	1,131,889	1,602,933	1,707,640
Capital assets	1,868,710	1,688,064	4,965,869	4,774,427	6,834,579	6,462,491
Other noncurrent assets	3,138	877	701,942	664,730	705,080	665,607
Total assets	2,401,051	2,264,692	6,741,541	6,571,046	9,142,592	8,835,738
Current liabilities	198,161	185,118	384,841	346,764	583,002	531,882
Noncurrent liabilities	854,763	832,137	4,059,289	4,067,578	4,914,052	4,899,715
Total liabilities	1,052,924	1,017,255	4,444,130	4,414,342	5,497,054	5,431,597
Net assets:						
Invested in capital assets, net of related debt	1,204,877	1,111,491	1,505,479	1,406,119	2,710,356	2,517,610
Restricted	100,469	28,492	216,459	202,651	316,928	231,143
Unrestricted	42,781	107,454	575,473	547,934	618,254	655,388
Total net assets	$ 1,348,127	1,247,437	2,297,411	2,156,704	3,645,538	3,404,141

(1) Certain prior year balances have been reclassified in order to provide more meaningful comparative data

As noted earlier, net assets may serve as a useful indicator of a government's financial position. For the City, assets exceeded liabilities by $3.6 billion at the close of the current fiscal year. However, the largest portion of the City's net assets are invested in capital assets (e.g. land, building, and equipment - 74%). The City uses these capital assets to provide services to citizens. Capital assets are generally not highly liquid; consequently, they are not considered future available resources. Although the City's investment in its capital assets is reported net of related debt, it should be noted that the resources needed to repay this debt must be provided from other sources since the capital assets themselves cannot be liquidated for these liabilities.

An additional portion of the City's net assets, $317 million (9%), represents resources that are subject to external restrictions on how they may be used. The remaining balance of unrestricted net assets, $618 million (17%), may be used to meet the government's future obligations.

At the end of the current fiscal year, the City is able to report positive balances in all three categories of net assets for the government as a whole, as well as for governmental and business-type activities separately.

FINANCIAL ANALYSIS OF THE GOVERNMENT-WIDE STATEMENTS, continued

b -- Changes in Net Assets

Total net assets of the City increased by $241.4 million in the current year. Governmental net assets increased $100.7 million, which is attributable to an increase in property tax revenue, an increase to unrestricted contributions, and a decrease to program expenses. The business-type net assets increased by $140.7 million, mainly attributable to an increase in operating revenues.

Changes in Net Assets
September 30
(in thousands)

	Governmental Activities		Business-Type Activities		Total	
	2003	2002	2003	2002	2003	2002
Program revenues:						
Charges for services	$ 75,469	84,349	1,368,616	1,174,755	1,444,085	1,259,104
Operating grants and contributions	55,122	53,374	--	--	55,122	53,374
Capital grants and contributions	3,956	1,203	48,325	43,537	52,281	44,740
General revenues:						
Property tax	233,130	224,396	--	--	233,130	224,396
Sales tax	110,454	115,441	--	--	110,454	115,441
Franchise fees and gross receipts tax	63,049	62,576	--	--	63,049	62,576
Grants and contributions not restricted to specific programs	94,210	19,137	--	--	94,210	19,137
Interest and other	24,975	23,746	30,430	58,180	55,405	81,926
Total revenues	660,365	584,222	1,447,371	1,276,472	2,107,736	1,860,694
Program expenses:						
General government	43,405	75,941	--	--	43,405	75,941
Public safety	292,411	279,533	--	--	292,411	279,533
Transportation, planning and sustainability	17,119	15,694	--	--	17,119	15,694
Public health	80,808	75,033	--	--	80,808	75,033
Public recreation and culture	58,199	71,863	--	--	58,199	71,863
Urban growth management	59,949	54,287	--	--	59,949	54,287
Unallocated depreciation expense - infrastructure	35,414	34,074	--	--	35,414	34,074
Interest on debt	39,296	35,771	--	--	39,296	35,771
Electric	--	--	754,393	610,374	754,393	610,374
Water	--	--	130,119	132,665	130,119	132,665
Wastewater	--	--	115,284	118,506	115,284	118,506
Airport	--	--	79,558	76,546	79,558	76,546
Convention	--	--	40,621	36,344	40,621	36,344
Other	--	--	119,763	115,518	119,763	115,518
Total expenses	626,601	642,196	1,239,738	1,089,953	1,866,339	1,732,149
Excess before special items and transfers	33,764	(57,974)	207,633	186,519	241,397	128,545
Special items - purchased land lease rights	--	(4,000)	--	--	--	(4,000)
Transfers	66,926	104,519	(66,926)	(104,519)	--	--
Increase in net assets	100,690	42,545	140,707	82,000	241,397	124,545
Beginning net assets	1,247,437	1,204,892	2,156,704	2,074,704	3,404,141	3,279,596
Ending net assets	$ 1,348,127	1,247,437	2,297,411	2,156,704	3,645,538	3,404,141

FINANCIAL ANALYSIS OF THE GOVERNMENT-WIDE STATEMENTS, continued

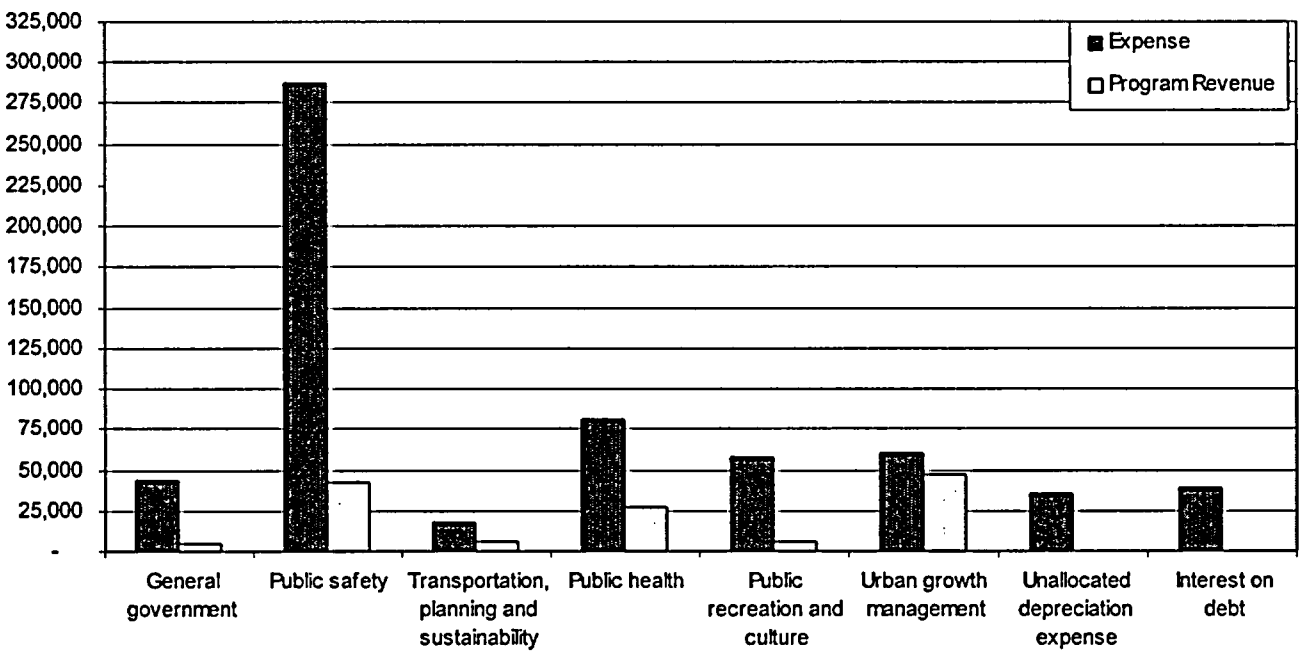
c – Program Revenues and Expenses – Governmental Activities

Governmental activities increased the City's net assets by $100.7 million, thereby accounting for a 3 percent increase in the City's total net assets and 42% of the current year increase in net assets. Key factors of this increase are as follows:

- The City's property tax revenue increased by $8.7 million, as a result of increasing assessed value; while the City's tax rate was unchanged at .4597 per $100 valuation.
- Sales and other taxes decreased during the year, with sales tax decreasing more than 4 percent as a result of the economic downturn.
- Grants and contributions not restricted to specific programs increased by $75.1 million during the year, primarily as a result of contributed infrastructure through annexations and developer contributions.
- Governmental expenses decreased $15.6 million, primarily from general government, as a result of decreased right of way acquisition costs which were contributed to other governmental entities and public recreation and culture reductions.

The chart below illustrates the City's governmental expense and revenues by function: general government; public safety; transportation, planning and sustainability; public health; public recreation and culture; urban growth management; unallocated depreciation expense and interest on debt.

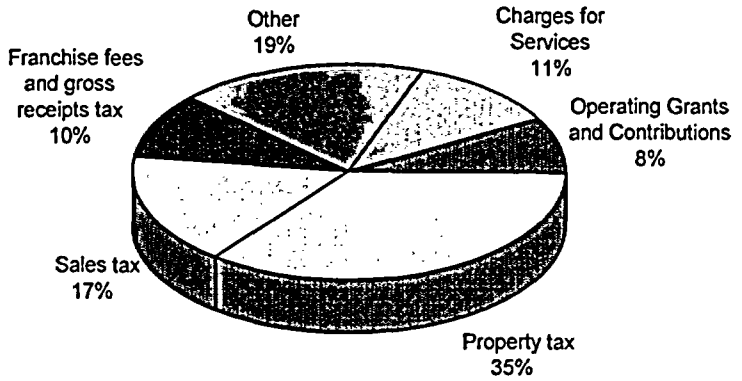
Government-wide Program Expenses and Revenues – Governmental Activities
(in thousands)



FINANCIAL ANALYSIS OF THE GOVERNMENT-WIDE STATEMENTS, *continued*

General revenues such as property taxes, sales taxes and franchise fees are not shown by program, but are used to support all governmental activities. Property taxes are the largest source of general governmental revenues, followed by sales taxes and charges for services.

Government-wide Revenues by Source -- Governmental Activities



d -- Program Revenues and Expenses -- Business-type activities

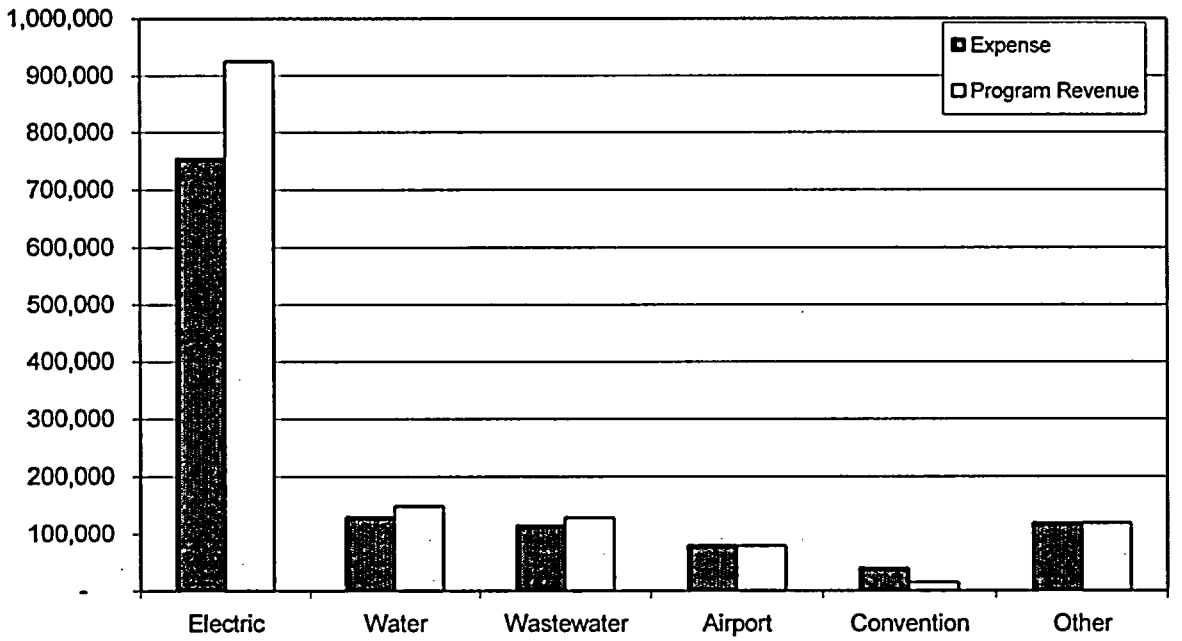
Business-type activities increased the City's net assets by $140.7 million, accounting for a 4% increase in the City's total net assets and 58% of the current year increase in net assets. Net program expenses and revenues are, as follows:

- Electric net assets increased $118 million, primarily from an increase in utility services revenue.
- Water and Wastewater net assets increased $14 million, due to an increase in utility services revenue. Expenses decreased due to cost reduction measures.
- Airport net assets increased $2 million. Although revenues decreased due to reduced air travel and expenses increased as a result of additional security costs, net assets showed positive growth.
- Convention net assets decreased $1.9 million, due primarily to a reduction of interest income of $2.4 million and an increase in transfers from other funds of approximately $1 million.

As shown in the following chart, the Electric utility, with expenses of $754 million, is the City's largest business-type activity, followed by Water ($130 million), Wastewater ($115 million), Airport ($80 million) and Convention ($41 million). For the fiscal year, operating revenues exceeded operating expenses for all business-type activities, except Convention and other business-type activities. Within other business-type activities, Hospital and Primary Care operating expenses exceeded operating revenues.

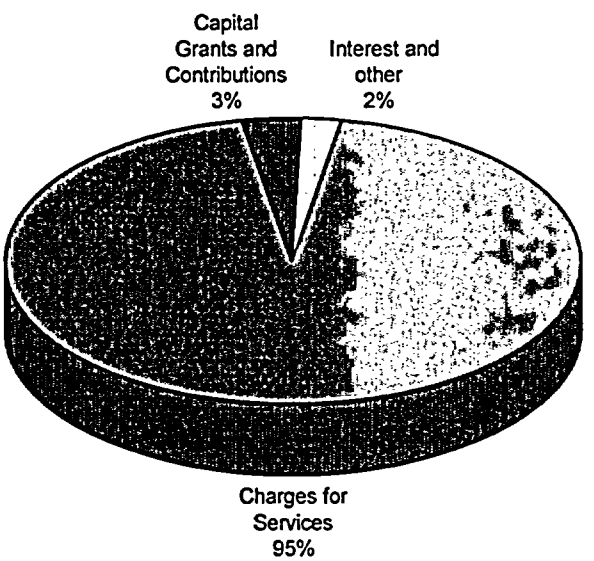
FINANCIAL ANALYSIS OF THE GOVERNMENT-WIDE STATEMENTS, continued

Government-wide Expenses and Program Revenues – Business-type Activities
(Excludes General Revenues and Transfers)
(in thousands)



For all business-type activities, charges for services provide the largest percentage of revenues (95%), followed by capital grants and contributions (3%) and interest and other revenues (2%).

Government-wide Revenue by Source – Business-type Activities



FINANCIAL ANALYSIS OF THE GOVERNMENT'S FUND LEVEL STATEMENTS

In comparison to the government-wide statements, the fund-level statements focus on the key funds of the City. The City uses fund accounting to ensure and demonstrate compliance with finance-related legal requirements.

a – Governmental funds

The City reports the following types of governmental funds: the General Fund, special revenue funds, debt service funds, capital project funds and permanent funds. The focus of the City's governmental funds is to provide information on near-term inflows, outflows and available resources. Such information is useful in assessing the City's financing requirements. In particular, unreserved fund balance may serve as a useful measure of a government's net resources available at the end of the fiscal year.

At the end of the year, the City of Austin's governmental funds reported combined ending fund balances of $345 million, a decrease of $38 million from the previous year. Approximately $218 million represents unreserved ending balance, which is available for future use. The remainder of fund balance is reserved and only available for commitments for the purchase of goods and services, in addition to certain debt payments. Reserved fund balance increased $3 million in comparison to the prior year, primarily due to an increase in the reservation for notes receivable of $2 million in the Housing Assistance Fund, a nonmajor special revenue fund.

The General Fund is the chief operating fund of the City. At the end of the current fiscal year, the unreserved fund balance of the General Fund was $88 million, while total fund balance was $93 million. As a measure of the General Fund's liquidity, it may be useful to compare both unreserved fund balance and total fund balance to total fund expenditures. Unreserved fund balance represents 20% of total General Fund expenditures of $433 million, and total fund balance represents 22% of expenditures. The unreserved and undesignated fund balance of the General Fund is $35 million, which may be designated by City Council for specified uses for the future.

The General Fund fund balance decreased by $412,000 during the fiscal year; undesignated fund balance decreased by $882,000. Significant differences from the previous year include:

- $15 million increase in revenues, primarily from property taxes and rental income.
- Increase of $2 million in expenditures. Although public safety expenditures increased by $13 million, other program expenditures decreased $11 million.
- $45 million decrease in transfers in, primarily from nonmajor enterprise funds.
- $12 million increase in transfers out, primarily for nonmajor enterprise funds and Capital Project funds.

b – Proprietary funds

The City's proprietary funds provide the same type of information found in the government-wide financial statements, but in more detail.

- Total Electric Fund net assets increased $118 million. Operating revenue for 2003 was $922 million, an increase of approximately 24% from the prior year. This increase was primarily due to increased fuel costs, which are recovered as a component of the electric rate. Operating expense before depreciation for 2003 was $554 million, an increase of approximately 38% from the prior year. This increase was primarily due to increased fuel costs.

- Total Water and Wastewater Fund net assets increased approximately $14 million or $8.5 million for Water and $5.5 million for Wastewater. Water operating revenue for 2003 was $130 million, an increase of approximately 6.9% from the prior year. Wastewater operating revenue for 2003 was $112 million, an increase of approximately 4.1% from the prior year. Sales were less than projected due to economic conditions and wetter than normal weather conditions during the summer months. Water operating expense before depreciation for 2003 was $59 million, a decrease of approximately 2% compared to the prior year. Wastewater operating expense before depreciation for 2003 was $50 million, a decrease of approximately 4% compared to the prior year. The decrease in expenses was due in part from the elimination of 35 full-time positions through attrition and less than anticipated utility transmission main breaks and the related operating expenses. The utility implemented cost containment strategies to reduce other operating costs during 2003.

FINANCIAL ANALYSIS OF THE GOVERNMENT'S FUND LEVEL STATEMENTS, continued

- The Airport Fund net assets increased over $2 million in 2003. Operating revenues were $63 million, a decrease of approximately $1 million from the prior year. Operating expenses before depreciation increased approximately $3.5 million as a result of increased security costs. Interest revenues were $2.5 million, a decrease of approximately 38% from the previous year. Interest revenue decreased due to lower interest rates and a reduction of pooled investments and cash through 2003. Capital contributions resulted in the remaining increase in net assets.

OTHER INFORMATION

a – General Fund budgetary highlights

The original budget of the General Fund was amended once during fiscal year 2003 by $1.3 million for increased public safety costs.

During the year, revenues were $8 million less than budgeted. A decline in sales tax collections was the primary cause of the difference.

Cost containment steps were put into place to reduce expenditures in order to offset the revenue shortfall. Expenditures were $14 million less than budgeted. Significant activities whose expenditures were less than budgeted include public safety ($5.4 million), public health ($2.4 million), and general city responsibilities ($2.3 million). Transfers out were also significantly less than budgeted ($9.2 million). The budget was not formally amended to reflect the cost containment actions.

The total fund balance at end of year amounted to $34 million, which was $22 million higher than budgeted. The increase was attributed to an increase of $15 million in the current year (excess of revenues and other sources over expenditures and other uses) and an increase of $7 million from the budgeted amount for the end of the previous fiscal year (fund balance at beginning of year).

b – Capital Assets

The City's capital assets for governmental and business-type activities as of September 30, 2003, total $6.8 billion (net of accumulated depreciation). Capital assets include land, buildings and improvements, equipment, vehicles, infrastructure, assets not classified, construction work in progress, nuclear fuel and plant held for future use. The total increase in the City's capital assets for the current fiscal year was $373 million (6 percent), with an increase of almost 11 percent for governmental activities and an increase of 4 percent for business-type activities. Additional information on capital assets can be found in Note 7. Capital asset balances are as follows:

Capital Assets, Net of Accumulated Depreciation
September 30
(in millions)

	Governmental Activities		Business-Type Activities		Total	
	2003	2002	2003	2002	2003	2002
Land and improvements	$ 195	151	270	267	465	418
Other assets not depreciated	18	17	1	1	19	18
Building and improvements	226	189	1,355	1,984	1,581	2,173
Equipment	26	17	2,270	1,571	2,296	1,588
Vehicles	36	34	36	36	72	70
Infrastructure	919	867	–	–	919	867
Completed assets not classified	95	190	320	555	415	745
Construction work in progress	354	223	661	311	1,015	534
Nuclear fuel, net of amortization	–	–	22	18	22	18
Plant held for future use	–	–	31	31	31	31
Total net assets	$ 1,869	1,688	4,966	4,774	6,835	6,462

OTHER INFORMATION, continued

Major capital asset events during the current fiscal year included the following:

- Governmental capital assets increased $181 million. Included in this increase were $89 million in infrastructure additions, $14 million in Parkland purchases and improvements, $12 million representing the City's investment in the Combined Emergency Center and $5 million in Fire and EMS emergency vehicles. Progress also continued on a new City Hall and numerous infrastructure improvement projects.
- Business-type activities purchased or completed construction on capital assets of $191 million. The Electric Fund added $83 million in plant and equipment expansions or improvements to existing facilities. The Water and Wastewater Fund increased capital assets by $104 million, including approximately $15 million of costs associated with the Austin Clean Water Program.

c – Debt Administration

At the end of the current fiscal year, the City reported $4.3 billion in outstanding debt. The table below reflects the outstanding debt at September 30. Additional information can be found in Note 10.

Outstanding Debt
General Obligation and Revenue Debt
(in millions)

	Governmental Activities		Business-Type Activities		Total	
	2003	2002	2003	2002	2003	2002
General obligation bonds and other tax supported debt, net	$ 830	795	79	82	909	877
Commercial paper notes, net	–	–	128	358	128	358
Revenue notes	–	–	28	28	28	28
Revenue bonds, net	–	–	3,218	2,989	3,218	2,989
Capital lease obligations	1	–	15	17	16	17
Total	$ 831	795	3,468	3,474	4,299	4,269

During fiscal year 2003, the City's total outstanding debt increased by $30 million. The City issued new debt and refinanced portions of existing debt to take advantage of lower borrowing costs. Debt issues include the following:

- Bond debt for governmental functions increased $36 million, and will be used primarily for street improvements; right of way acquisition and utility relocation; park and recreation facilities; emergency centers; and a court settlement agreement.
- Bond debt for business-type functions decreased $6 million due to the payment of existing debt. In 2003, new debt was issued primarily for communications technology upgrades; public safety equipment; creek restoration; and developer reimbursements. The City issued Electric refunding and Water and Wastewater refunding bonds to refund taxable and tax-exempt Commercial Paper.

The City continues to maintain excellent credit ratings on debt issues, with ratings remaining unchanged during the year. Ratings at September 30, 2003 of the City's obligations for various debt instruments are as follows:

Debt	Moody's Investors Service, Inc	Standard and Poor's	Fitch, Inc.
General obligation bonds and other tax supported debt	Aa2	AA+	AA+
Commercial paper notes	P-1	A-1	F1+
Commercial paper notes - taxable	P-1	A-1+	F1+
Revenue bonds - prior lien	A2	A	A+
Revenue bonds - subordinate lien	A2	A-	A+
Revenue bonds - separate lien:			
Electric	A3	A-	A
Water and Wastewater	A2	A-	A+

OTHER INFORMATION, continued

d -- Economic Factors and Next Year's Budget and Rates

The City faces a significant challenge for next year's budget. The economic downturn has continued without any significant positive signs that a recovery will occur in the near future. Nationwide, major city and state governments are facing the same type of budget crisis that Austin has experienced.

Sales tax for fiscal year 2003 was projected to decrease by 5.5%, but ended the year at a decline of 4.5% instead. For fiscal year 2004, the City's approved budget reflects an annual growth rate of 2%. Overall, property values for 2004 will have negative growth for the first time in twelve years. Commercial and multi-family property values are expected to decline by approximately 13%. In addition, costs associated with public safety will continue to increase as a result of increased homeland security requirements.

The City instituted an aggressive response to the economic downturn beginning in 2002 and continuing throughout 2003. Significant reductions in General Fund costs (other than public safety) allowed the City to balance its budget without raising taxes, closing facilities, eliminating programs or laying off employees.

For 2004, the City will continue to focus on making structural changes in City operations that will result in long-term, as well as short-term cost savings. In order to achieve necessary cost reductions, approximately $38 million will be cut from the General Fund. In addition, the property tax rate will increase to 49.28 cents per $100 valuation, which is the effective tax rate based on the decline in property valuations. The increase from the previous year rate is approximately 3 cents or 7%. The budget will also include a rate increase in Water and Wastewater fees of 5.9%. The increase is necessary to fund the Austin Clean Water Program, a mandate imposed by the U.S. Environmental Protection Agency.

e -- Requests for Information

This financial report is designed to provide our citizens, taxpayers, customers, investors and creditors with a general overview of the City's finances and to demonstrate the City's accountability for the money it receives. If you have questions about this report or need additional financial information, contact the Financial Services Department of the City of Austin, P.O. Box 1088, Austin, Texas 78767, or (512) 974-3344 or on the web at http://www.ci.austin.tx.us/controller/.

BASIC FINANCIAL STATEMENTS

CITY OF AUSTIN
FOUNDED 1839

Statement of Net Assets
September 30, 2003
(In thousands)

City of Austin, Texas
Exhibit A-1

	Governmental Activities	Business-type Activities	2003 Total (†)
ASSETS			
Current assets:			
Cash	$ 112	51	163
Pooled investments and cash	311,549	69,146	380,695
Pooled investments and cash - designated	–	36,701	36,701
Pooled investments and cash - restricted	–	220,708	220,708
Total pooled investments and cash	311,549	326,555	638,104
Investments, at fair value - designated	14,685	155,611	170,296
Investments, at fair value - restricted	–	281,025	281,025
Cash held by trustee	10,279	–	10,279
Cash held by trustee - restricted	–	10,009	10,009
Working capital advances	–	2,880	2,880
Property taxes receivable	11,017	–	11,017
Less allowance for uncollectible taxes	(1,852)	–	(1,852)
Net property taxes receivable	9,165	–	9,165
Accounts and other taxes receivable	243,014	171,923	414,937
Less allowance for doubtful accounts	(88,564)	(7,402)	(95,966)
Net accounts receivable	154,450	164,521	318,971
Interest receivable - restricted	266	2,527	2,793
Receivables from other governments	12,586	326	12,912
Notes receivable, net of allowance	9,016	–	9,016
Internal balances	(3,006)	(310)	(3,316)
Internal balances - restricted	–	3,316	3,316
Inventories, at cost	2,504	47,070	49,574
Real property held for resale	5,984	–	5,984
Prepaid expenses	483	1,237	1,720
Other assets	1,130	71,385	72,515
Other receivables - restricted	–	7,527	7,527
Total current assets	529,203	1,073,730	1,602,933
Noncurrent assets:			
Investments, at fair value	–	65,000	65,000
Investments held by trustee - restricted	–	88,044	88,044
Interest receivable - restricted	–	878	878
Capital assets			
Land and other nondepreciable assets	212,939	271,327	484,266
Property, plant and equipment in service	1,851,742	6,123,925	7,975,667
Less accumulated depreciation	(549,922)	(2,143,724)	(2,693,646)
Net property, plant and equipment in service	1,301,820	3,980,201	5,282,021
Construction in progress	353,951	661,157	1,015,108
Nuclear fuel, net of amortization	–	21,805	21,805
Plant held for future use	–	31,379	31,379
Total capital assets	1,868,710	4,965,869	6,834,579
Intangible assets, net of amortization	–	90,102	90,102
Other long-term assets	–	1,913	1,913
Deferred costs and expenses, net of amortization	3,138	456,005	459,143
Total noncurrent assets	1,871,848	5,667,811	7,539,659
Total assets	$ 2,401,051	6,741,541	9,142,592

(†) After internal receivables and payables have been eliminated.

(Continued)

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

	Governmental Activities	Business-type Activities	2003 Total (†)
LIABILITIES			
Current liabilities:			
Accounts payable	$ 27,496	52,668	80,164
Accounts and retainage payable from restricted assets	–	41,773	41,773
Accrued payroll	10,978	6,638	17,616
Accrued compensated absences	28,125	13,115	41,240
Claims payable	20,121	–	20,121
Accrued interest payable from restricted assets	–	66,713	66,713
Interest payable on other debt	3,985	948	4,933
General obligation bonds payable and other tax supported debt, net of discount and inclusive of premium	50,438	3,301	53,739
General obligation bonds payable and other tax supported debt payable from restricted assets, net of discount and inclusive of premium	–	5,096	5,096
Revenue bonds payable	–	2,455	2,455
Revenue bonds payable payable from restricted assets	–	134,116	134,116
Capital lease obligations payable	533	3,215	3,748
Customer and escrow deposits payable from restricted assets	–	10,700	10,700
Nuclear fuel expense payable from restricted assets	–	29,531	29,531
Deferred credits and other liabilities	56,485	14,572	71,057
Total current liabilities	198,161	384,841	583,002
Noncurrent liabilities, net of current portion:			
Accrued compensated absences	41,118	7,804	48,922
Claims payable	14,627	–	14,627
Capital appreciation bond interest payable	–	150,972	150,972
Commercial paper notes payable, net of discount	–	128,484	128,484
Revenue notes payable	–	28,000	28,000
General obligation bonds payable and other tax supported debt, net of discount and inclusive of premium	779,320	70,490	849,810
Revenue bonds payable, net of discount and inclusive of premium	–	3,081,509	3,081,509
Capital lease obligations payable	260	11,950	12,210
Accrued landfill closure and postclosure costs	–	7,370	7,370
Decommissioning expense payable from restricted assets	–	90,687	90,687
Deferred credits and other liabilities	19,438	477,462	496,900
Other liabilities payable from restricted assets	–	4,561	4,561
Total noncurrent liabilities	854,763	4,059,289	4,914,052
Total liabilities	1,052,924	4,444,130	5,497,054
NET ASSETS			
Invested in capital assets, net of related debt	1,204,877	1,505,479	2,710,356
Restricted for:			
Debt service	13,592	111,446	125,038
Bond reserve	–	18,688	18,688
Capital projects	74,397	65,712	140,109
Renewal and replacement	–	11,330	11,330
Passenger facility charges	–	7,326	7,326
Convention Center operating reserve	–	1,957	1,957
Perpetual Care:			
Expendable	313	–	313
Nonexpendable	1,040	–	1,040
Other purposes	11,127	–	11,127
Unrestricted	42,781	575,473	618,254
Total net assets	$ 1,348,127	2,297,411	3,645,538

(†) After internal receivables and payables have been eliminated.

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

Statement of Activities
For the year ended September 30, 2003
(In thousands)

City of Austin, Texas
Exhibit A-2

Functions/Programs	Expenses	Program Revenues: Charges for Services	Program Revenues: Operating Grants and Contributions	Program Revenues: Capital Grants and Contributions	Net (Expense) Revenue and Changes in Net Assets: Governmental Activities	Net (Expense) Revenue and Changes in Net Assets: Business-type Activities	Net (Expense) Revenue and Changes in Net Assets: 2003 Total
Governmental activities							
General government	$ 43,405	4,791	293	--	(38,321)	--	(38,321)
Public safety	292,411	36,579	6,324	--	(249,508)	--	(249,508)
Transportation, planning and sustainability	17,119	5,142	324	853	(10,800)	--	(10,800)
Public health	80,808	8,100	15,941	3,054	(53,713)	--	(53,713)
Public recreation and culture	58,199	2,551	3,625	49	(51,974)	--	(51,974)
Urban growth management	59,949	18,306	28,615	--	(13,028)	--	(13,028)
Unallocated depreciation expense	35,414	--	--	--	(35,414)	--	(35,414)
Interest on debt	39,296	--	--	--	(39,296)	--	(39,296)
Total governmental activities	626,601	75,469	55,122	3,956	(492,054)	--	(492,054)
Business-type activities							
Electric	754,393	921,649	--	3,437	--	170,693	170,693
Water	130,119	130,424	--	18,214	--	18,519	18,519
Wastewater	115,284	111,941	--	17,471	--	14,128	14,128
Airport	79,558	71,693	--	7,524	--	(341)	(341)
Convention	40,621	15,040	--	--	--	(25,581)	(25,581)
Other	119,763	117,869	--	1,679	--	(215)	(215)
Total business-type activities	1,239,738	1,368,616	--	48,325	--	177,203	177,203
Total	$ 1,866,339	1,444,085	55,122	52,281	(492,054)	177,203	(314,851)
General revenues:							
Property tax					233,130	--	233,130
Sales tax					110,454	--	110,454
Franchise fees and gross receipts tax					63,049	--	63,049
Grants and contributions not restricted to specific programs					94,210	--	94,210
Interest and other					24,975	30,430	55,405
Transfers					66,926	(66,926)	--
Total general revenues and transfers					592,744	(36,496)	556,248
Change in net assets					100,690	140,707	241,397
Beginning net assets					1,247,437	2,156,704	3,404,141
Ending net assets					$ 1,348,127	2,297,411	3,645,538

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

CITY OF AUSTIN
FOUNDED 1839

Governmental Funds
Balance Sheet
September 30, 2003
(In thousands)

City of Austin, Texas
Exhibit B-1

	2003		
	General Fund	Nonmajor Governmental Funds	Total Governmental Funds
ASSETS			
Cash	$ 89	5	94
Pooled investments and cash	84,451	167,045	251,496
Investments, at fair value	–	14,685	14,685
Cash held by trustee	–	9,791	9,791
Property taxes receivable	6,715	4,302	11,017
Less allowance for uncollectible taxes	(1,155)	(697)	(1,852)
Net property taxes receivable	5,560	3,605	9,165
Accounts and other taxes receivable	81,259	96,970	178,229
Less allowance for doubtful accounts	(52,166)	(386)	(52,552)
Net accounts receivable	29,093	96,584	125,677
Receivables from other governments	–	12,586	12,586
Notes receivable, net of allowance	–	9,016	9,016
Due from other funds	–	36,925	36,925
Advances to other funds	–	4,677	4,677
Inventories, at cost	775	–	775
Real property held for resale	–	5,984	5,984
Prepaid expenses	214	11	225
Other assets	–	1,130	1,130
Total assets	120,182	362,044	482,226
LIABILITIES AND FUND BALANCES			
Accounts payable	3,446	17,824	21,270
Accrued payroll	8,687	49	8,736
Accrued compensated absences	605	6	611
Due to other funds	706	36,919	37,625
Deferred revenue	5,432	6,282	11,714
Advances from other funds	2,217	248	2,465
Deposits and other liabilities	5,883	48,467	54,350
Total liabilities	26,976	109,795	136,771
Fund balances			
Reserved:			
Encumbrances	4,123	88,755	92,878
Inventories and prepaid items	989	–	989
Notes receivable	–	9,016	9,016
Real property held for resale	–	5,984	5,984
Debt service	–	17,311	17,311
Permanent funds	–	1,040	1,040
Unreserved, designated:			
Emergencies	15,000	–	15,000
Contingencies	4,358	–	4,358
Future use	540	–	540
Budget stabilization	33,000	–	33,000
Special revenue	–	25,388	25,388
Unreserved, undesignated:			
General Fund	35,196	–	35,196
Capital projects	–	104,442	104,442
Permanent funds	–	313	313
Total fund balances	93,206	252,249	345,455
Total liabilities and fund balances	$ 120,182	362,044	482,226

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

Governmental Funds
Reconciliation of the Governmental Funds Balance Sheet
to the Statement of Net Assets
September 30, 2003
(In thousands)

City of Austin, Texas
Exhibit B-1.1

Total fund balances - Governmental funds	$ 345,455
Amounts reported for governmental activities in the statement of net assets are different because:	
Capital assets used in governmental activities are not financial resources and, therefore, are not reported in the funds.	1,829,118
Other long-term assets are not available as current-period resources and are not reported in the funds.	18,617
Long-term liabilities are not payable in the current period and are not reported in the funds.	(886,719)
Internal service funds are used by management to charge the costs of capital project management, employee benefits, fleet maintenance, information systems, liability reserve, support services, wireless communication, and workers' compensation to individual funds. The assets and liabilities of the internal service funds are included in governmental activities in the statement of net assets.	41,656
Total net assets - Governmental activities	$ 1,348,127

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

Governmental Funds
Statement of Revenues, Expenditures and Changes in Fund Balances
For the year ended September 30, 2003
(In thousands)

	2003		
	General Fund	Nonmajor Governmental Funds	Total Governmental Funds
REVENUES			
Property taxes	$ 150,378	82,195	232,573
Sales taxes	110,454	–	110,454
Franchise fees and other taxes	32,641	30,409	63,050
Fines, forfeitures and penalties	16,966	4,000	20,966
Licenses, permits and inspections	14,737	–	14,737
Charges for services/goods	15,403	24,463	39,866
Intergovernmental	–	74,392	74,392
Property owners' participation and contributions	–	10,937	10,937
Interest and other	19,815	9,930	29,745
Total revenues	360,394	236,326	596,720
EXPENDITURES			
Current:			
General government	43,276	1,019	44,295
Public safety	263,477	14,820	278,297
Transportation, planning and sustainability	10,337	3,776	14,113
Public health	56,606	23,864	80,470
Public recreation and culture	46,943	5,893	52,836
Urban growth management	12,240	47,321	59,561
Debt service:			
Principal	–	49,340	49,340
Interest	–	38,529	38,529
Fees and commissions	–	8	8
Capital outlay	–	155,517	155,517
Total expenditures	432,879	340,087	772,966
Excess (deficiency) of revenues over expenditures	(72,485)	(103,761)	(176,246)
OTHER FINANCING SOURCES (USES)			
Issuance of tax supported debt	–	70,323	70,323
Issuance of refunding bonds	–	62,514	62,514
Payment to escrow agent	–	(62,514)	(62,514)
Capital leases	785	106	891
Transfers in	92,417	36,841	129,258
Transfers out	(21,129)	(41,047)	(62,176)
Total other financing sources (uses)	72,073	66,223	138,296
Net change in fund balances	(412)	(37,538)	(37,950)
Fund balances at beginning of year	93,618	289,787	383,405
Fund balances at end of year	$ 93,206	252,249	345,455

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

Net change in fund balances - Governmental funds	$	(37,950)
Governmental funds report capital outlays as expenditures. However, in the statement of activities the cost of those assets is allocated over their estimated useful lives and reported as depreciation expense. This is the amount by which capital outlays exceeded depreciation in the current period.		104,186
Revenues in the statement of activities that do not provide current available financial resources are not reported as revenues in the funds.		71,835
Revenues in the governmental funds are recognized when measurable and available, but are deferred in the statement of activities until earned, regardless of when collected.		(14,957)
The issuance of long-term debt (e.g., bonds, leases) provides current financial resources to governmental funds, while the repayment of the principal of long-term debt consumes the current financial resources of governmental funds. Neither transaction, however, has any effect on net assets. Also, governmental funds report the effect of issuance costs, premiums, discounts, and similar items when debt is first issued, whereas these amounts are deferred and amortized in the statement of activities. This amount is the net effect of these differences in the treatment of long-term debt and related items.		(20,983)
Some expenses reported in the statement of activities do not require the use of current financial resources and therefore are not reported as expenditures in the funds.		(5,249)
The net revenue of certain activities of internal service funds is reported with governmental activities.		3,808
Change in net assets - Governmental activities	$	100,690

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

Proprietary Funds
Statement of Net Assets
September 30, 2003
(In thousands)

	Electric	Water and Wastewater	Airport
ASSETS			
Current assets:			
Cash	$ 18	11	5
Pooled investments and cash	18,468	18,938	1,915
Pooled investments and cash - designated	16,877	199	–
Pooled investments and cash - restricted	52,065	27,769	81,721
Total pooled investments and cash	87,410	46,906	83,636
Investments, at fair value - designated	153,780	1,534	–
Investments, at fair value - restricted	150,899	89,010	27,105
Cash held by trustee	–	–	–
Cash held by trustee - restricted	4,427	5,582	–
Working capital advances	2,756	–	–
Accounts receivable	115,841	37,186	4,044
Less allowance for doubtful accounts	(2,314)	(1,066)	(150)
Net accounts receivable	113,527	36,120	3,894
Interest receivable - restricted	1,876	550	–
Receivables from other governments	–	–	–
Due from other funds - restricted	–	27	700
Inventories, at cost	45,389	1,134	–
Prepaid expenses	973	132	1
Other assets	71,384	1	–
Other receivables - restricted	1,501	365	1,861
Total current assets	633,940	181,372	117,202
Noncurrent assets:			
Advances to other funds	2,520	–	–
Advances to other funds - restricted	–	188	2,401
Investments, at fair value	65,000	–	–
Investments held by trustee - restricted	88,044	–	–
Interest receivable - restricted	878	–	–
Capital assets			
Land and other nondepreciable assets	34,942	136,173	59,149
Property, plant and equipment in service	2,951,409	2,121,656	615,235
Less accumulated depreciation	(1,288,675)	(658,184)	(86,583)
Net property, plant and equipment in service	1,662,734	1,463,472	528,652
Construction in progress	359,749	232,170	19,368
Nuclear fuel, net of amortization	21,805	–	–
Plant held for future use	31,379	–	–
Total capital assets	2,110,609	1,831,815	607,169
Intangible assets, net of amortization	–	90,102	–
Other long-term assets	1,911	2	–
Deferred costs and expenses, net of amortization	237,602	197,942	2,086
Total noncurrent assets	2,506,564	2,120,049	611,656
Total assets	$ 3,140,504	2,301,421	728,858

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

	Nonmajor Enterprise Funds	2003 Total	Governmental Activities- Internal Service Funds
ASSETS			
Current assets:			
Cash	17	51	18
Pooled investments and cash	29,825	69,146	60,053
Pooled investments and cash - designated	19,625	36,701	–
Pooled investments and cash - restricted	59,153	220,708	–
Total pooled investments and cash	108,603	326,555	60,053
Investments, at fair value - designated	297	155,611	–
Investments, at fair value - restricted	14,011	281,025	–
Cash held by trustee	–	–	488
Cash held by trustee - restricted	–	10,009	–
Working capital advances	124	2,880	–
Accounts receivable	14,852	171,923	10,644
Less allowance for doubtful accounts	(3,872)	(7,402)	(222)
Net accounts receivable	10,980	164,521	10,422
Interest receivable - restricted	101	2,527	–
Receivables from other governments	326	326	–
Due from other funds - restricted	–	727	–
Inventories, at cost	547	47,070	1,729
Prepaid expenses	131	1,237	258
Other assets	–	71,385	–
Other receivables - restricted	3,800	7,527	–
Total current assets	138,937	1,071,451	72,968
Noncurrent assets:			
Advances to other funds	64	2,584	–
Advances to other funds - restricted	–	2,589	–
Investments, at fair value	–	65,000	–
Investments held by trustee - restricted	–	88,044	–
Interest receivable - restricted	–	878	–
Capital assets			
Land and other nondepreciable assets	41,063	271,327	486
Property, plant and equipment in service	435,625	6,123,925	57,492
Less accumulated depreciation	(110,282)	(2,143,724)	(22,877)
Net property, plant and equipment in service	325,343	3,980,201	34,615
Construction in progress	49,870	661,157	4,491
Nuclear fuel, net of amortization	–	21,805	–
Plant held for future use	–	31,379	–
Total capital assets	416,276	4,965,869	39,592
Intangible assets, net of amortization	–	90,102	–
Other long-term assets	–	1,913	–
Deferred costs and expenses, net of amortization	18,375	456,005	7
Total noncurrent assets	434,715	5,672,984	39,599
Total assets	573,652	6,744,435	112,567

The accompanying notes are an integral part of the financial statements. (Continued)

Proprietary Funds
Statement of Net Assets
September 30, 2003
(In thousands)

	Electric	Water and Wastewater	Airport
LIABILITIES			
Current liabilities:			
Accounts payable	$ 44,810	1,118	1,332
Accounts and retainage payable from restricted assets	14,187	23,882	976
Accrued payroll	2,816	1,513	478
Accrued compensated absences	5,719	3,041	894
Claims payable	–	–	–
Due to other funds	–	–	–
Accrued interest payable from restricted assets	29,922	23,351	8,379
Interest payable on other debt	82	677	6
General obligation bonds payable and other tax supported debt	–	–	121
General obligation bonds payable and other tax supported debt payable from restricted assets	445	4,261	–
Revenue bonds payable	–	2,455	–
Revenue bonds payable from restricted assets	93,374	28,337	7,195
Capital lease obligations payable	2,035	1,036	11
Customer and escrow deposits payable from restricted assets	5,884	1,976	571
Nuclear fuel expense payable from restricted assets	29,531	–	–
Deferred credits and other liabilities	11,092	1,775	1,317
Total current liabilities	239,897	93,422	21,280
Noncurrent liabilities, net of current portion:			
Accrued compensated absences	4,047	1,822	468
Claims payable	–	–	–
Advances from other funds	–	3,293	–
Capital appreciation bond interest payable	75,889	75,083	–
Commercial paper notes payable, net of discount	54,672	73,812	–
Revenue notes payable	–	–	28,000
General obligation bonds payable and other tax supported debt, net of discount and inclusive of premium	2,882	20,409	591
Revenue bonds payable, net of discount and inclusive of premium	1,317,591	1,185,015	350,067
Capital lease obligations payable	7,072	4,760	11
Accrued landfill closure and postclosure costs	–	–	–
Decommissioning expense payable from restricted assets	90,687	–	–
Deferred credits and other liabilities	67,988	406,557	2,917
Other liabilities payable from restricted assets	1,649	581	2,331
Total noncurrent liabilities	1,622,477	1,771,332	384,385
Total liabilities	1,862,374	1,864,754	405,665
NET ASSETS			
Invested in capital assets, net of related debt	858,021	259,498	223,544
Restricted for:			
Debt service	60,463	21,808	21,921
Bond reserve	5,633	13,055	–
Capital projects	–	–	52,714
Renewal and replacement	–	–	10,000
Passenger facility charges	–	–	7,326
Convention Center operating reserve	–	–	–
Unrestricted	354,013	142,306	7,688
Total net assets	$ 1,278,130	436,667	323,193
Reconciliation to government-wide Statement of Net Assets			
Adjustment to consolidate internal service activities	1,666	1,169	460
Total net assets - Business-type activities	$ 1,279,796	437,836	323,653

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

	Nonmajor Enterprise Funds	2003 Total	Governmental Activities- Internal Service Funds
LIABILITIES			
Current liabilities:			
Accounts payable	5,408	52,668	6,226
Accounts and retainage payable from restricted assets	2,728	41,773	–
Accrued payroll	1,831	6,638	2,242
Accrued compensated absences	3,461	13,115	4,207
Claims payable	–	–	20,121
Due to other funds	–	–	27
Accrued interest payable from restricted assets	5,061	66,713	–
Interest payable on other debt	183	948	142
General obligation bonds payable and other tax supported debt	3,180	3,301	2,114
General obligation bonds payable and other tax supported debt payable from restricted assets	390	5,096	–
Revenue bonds payable	–	2,455	–
Revenue bonds payable from restricted assets	5,210	134,116	–
Capital lease obligations payable	133	3,215	317
Customer and escrow deposits payable from restricted assets	2,269	10,700	–
Nuclear fuel expense payable from restricted assets	–	29,531	–
Deferred credits and other liabilities	388	14,572	889
Total current liabilities	30,242	384,841	36,285
Noncurrent liabilities, net of current portion:			
Accrued compensated absences	1,467	7,804	2,611
Claims payable	–	–	14,627
Advances from other funds	3,696	6,989	396
Capital appreciation bond interest payable	–	150,972	–
Commercial paper notes payable, net of discount	–	128,484	–
Revenue notes payable	–	28,000	–
General obligation bonds payable and other tax supported debt, net of discount and inclusive of premium	46,608	70,490	12,777
Revenue bonds payable, net of discount and inclusive of premium	228,836	3,081,509	–
Capital lease obligations payable	107	11,950	120
Accrued landfill closure and postclosure costs	7,370	7,370	–
Decommissioning expense payable from restricted assets	–	90,687	–
Deferred credits and other liabilities	–	477,462	–
Other liabilities payable from restricted assets	–	4,561	–
Total noncurrent liabilities	288,084	4,066,278	30,531
Total liabilities	318,326	4,451,119	66,816
NET ASSETS			
Invested in capital assets, net of related debt	164,416	1,505,479	21,324
Restricted for:			
Debt service	7,254	111,446	–
Bond reserve	–	18,688	–
Capital projects	12,998	65,712	7,137
Renewal and replacement	1,330	11,330	–
Passenger facility charges	–	7,326	–
Convention Center operating reserve	1,957	1,957	–
Unrestricted	67,371	571,378	17,290
Total net assets	255,326	2,293,316	45,751
Reconciliation to government-wide Statement of Net Assets			
Adjustment to consolidate internal service activities	800	4,095	
Total net assets - Business-type activities	256,126	2,297,411	

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

Proprietary Funds
Statement of Revenues, Expenses and Changes in Fund Net Assets
For the year ended September 30, 2003
(In thousands)

	Electric	Water and Wastewater	Airport
OPERATING REVENUES			
Utility services	$ 921,649	242,365	–
User fees and rentals	–	–	63,479
Billings to departments	–	–	–
Employee contributions	–	–	–
Operating revenues from other governments	–	–	–
Other operating revenues	–	–	–
Total operating revenues	921,649	242,365	63,479
OPERATING EXPENSES			
Operating expenses before depreciation	554,235	109,416	40,786
Depreciation and amortization	89,757	50,480	15,962
Total operating expenses	643,992	159,896	56,748
Operating income (loss)	277,657	82,469	6,731
NONOPERATING REVENUES (EXPENSES)			
Interest and other revenues	22,080	3,578	2,484
Interest on revenue bonds and other debt	(104,091)	(79,606)	(23,236)
Interest capitalized during construction	–	–	685
Passenger facility charges	–	–	8,214
Amortization of bond issue cost	(831)	(565)	(105)
Cost (recovered) to be recovered in future years	11,982	(5,066)	–
Other nonoperating revenue (expense)	(17,530)	22	(160)
Total nonoperating revenues (expenses)	(88,390)	(81,637)	(12,118)
Income (loss) before contributions and transfers	189,267	832	(5,387)
Capital contributions	3,437	35,685	7,524
Transfers in	–	–	–
Transfers out	(74,636)	(22,515)	(48)
Change in net assets	118,068	14,002	2,089
Total net assets - beginning	1,160,062	422,665	321,104
Total net assets - ending	$ 1,278,130	436,667	323,193
Reconciliation to government-wide Statement of Activities			
Change in net assets	118,068	14,002	2,089
Adjustment to consolidate internal service activities	69	(292)	6
Change in net assets - Business-type activities	$ 118,137	13,710	2,095

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

	Nonmajor Enterprise Funds	2003 Total	Governmental Activities- Internal Service Funds
OPERATING REVENUES			
Utility services	–	1,164,014	–
User fees and rentals	128,030	191,509	–
Billings to departments	–	–	190,461
Employee contributions	–	–	22,073
Operating revenues from other governments	2,269	2,269	–
Other operating revenues	2,610	2,610	11,765
Total operating revenues	132,909	1,360,402	224,299
OPERATING EXPENSES			
Operating expenses before depreciation	130,892	835,329	218,739
Depreciation and amortization	12,801	169,000	1,697
Total operating expenses	143,693	1,004,329	220,436
Operating income (loss)	(10,784)	356,073	3,863
NONOPERATING REVENUES (EXPENSES)			
Interest and other revenues	2,288	30,430	435
Interest on revenue bonds and other debt	(16,312)	(223,245)	(610)
Interest capitalized during construction	1,814	2,499	–
Passenger facility charges	–	8,214	–
Amortization of bond issue cost	(173)	(1,674)	(4)
Cost (recovered) to be recovered in future years	–	6,916	–
Other nonoperating revenue (expense)	(1,822)	(19,490)	459
Total nonoperating revenues (expenses)	(14,205)	(196,350)	280
Income (loss) before contributions and transfers	(24,989)	159,723	4,143
Capital contributions	1,679	48,325	(594)
Transfers in	32,034	32,034	–
Transfers out	(1,761)	(98,960)	(156)
Change in net assets	6,963	141,122	3,393
Total net assets - beginning	248,363	2,152,194	42,358
Total net assets - ending	255,326	2,293,316	45,751
Reconciliation to government-wide Statement of Activities			
Change in net assets	6,963	141,122	
Adjustment to consolidate internal service activities	(198)	(415)	
Change in net assets - Business-type activities	6,765	140,707	

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

Proprietary Funds
Statement of Cash Flows
For the year ended September 30, 2003
(In thousands)

	Electric	Water and Wastewater	Airport
CASH FLOWS FROM OPERATING ACTIVITIES:			
Cash received from customers	$ 837,121	228,007	62,081
Cash payments to suppliers for goods and services	(437,704)	(57,130)	(24,510)
Cash payments to employees for services	(88,006)	(53,548)	(18,271)
Cash payments to claimants/beneficiaries	--	--	--
Cash received from other governments	--	--	--
Taxes collected and remitted to other governments	(23,282)	--	--
Net cash provided (used) by operating activities	288,129	117,329	19,300
CASH FLOWS FROM NONCAPITAL FINANCING ACTIVITIES:			
Transfers in	--	--	--
Transfers out	(74,636)	(22,515)	(48)
Interest paid on revenue notes and other debt	(19)	(19)	--
Increase in deferred assets	(1,829)	--	--
Loans to other funds	(2,520)	--	(73)
Loans from other funds	--	1,559	700
Loan repayments to other funds	--	--	--
Loan repayments from other funds	--	27	--
Net cash provided (used) by noncapital financing activities	(79,004)	(20,948)	579
CASH FLOWS FROM CAPITAL AND RELATED FINANCING ACTIVITIES:			
Proceeds from the sale of commercial paper notes	41,052	40,170	--
Proceeds from long-term loans	2,059	--	--
Principal paid on long-term debt	(70,083)	(26,631)	(5,783)
Proceeds from the sale of capital assets	1,920	--	--
Purchased interest received	879	590	--
Interest paid on revenue bonds and other debt	(87,891)	(65,254)	(22,833)
Passenger facility charges	--	--	8,214
Acquisition and construction of capital assets	(193,207)	(122,035)	(13,107)
Contributions from municipality	--	--	--
Contributions from State and Federal governments	--	--	7,137
Contributions in aid of construction	3,413	15,176	83
Bond issuance costs	(1,606)	(1,045)	--
Bond discounts	(568)	(673)	--
Bond premiums	7,925	4,644	--
Bonds issued for advanced refundings of debt	182,100	127,577	--
Cash paid for bond refunding escrow	(187,325)	(134,790)	--
Cash paid for nuclear fuel inventory	(9,683)	--	--
Net cash provided (used) by capital and related financing activities	$ (311,015)	(162,271)	(26,289)

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

	Nonmajor Enterprise Funds	2003 Total	Governmental Activities-Internal Service Funds
CASH FLOWS FROM OPERATING ACTIVITIES:			
Cash received from customers	129,094	1,256,303	214,132
Cash payments to suppliers for goods and services	(61,449)	(580,793)	(64,073)
Cash payments to employees for services	(66,462)	(226,287)	(82,266)
Cash payments to claimants/beneficiaries	–	–	(69,552)
Cash received from other governments	2,686	2,686	–
Taxes collected and remitted to other governments	–	(23,282)	–
Net cash provided (used) by operating activities	3,869	428,627	(1,759)
CASH FLOWS FROM NONCAPITAL FINANCING ACTIVITIES:			
Transfers in	32,034	32,034	–
Transfers out	(1,761)	(98,960)	(156)
Interest paid on revenue notes and other debt	(2)	(40)	–
Increase in deferred assets	–	(1,829)	–
Loans to other funds	(40)	(2,633)	–
Loans from other funds	3,056	5,315	59
Loan repayments to other funds	(1,242)	(1,242)	(27)
Loan repayments from other funds	1,689	1,716	–
Net cash provided (used) by noncapital financing activities	33,734	(65,639)	(124)
CASH FLOWS FROM CAPITAL AND RELATED FINANCING ACTIVITIES:			
Proceeds from the sale of commercial paper notes	–	81,222	–
Proceeds from long-term loans	–	2,059	–
Principal paid on long-term debt	(6,796)	(109,293)	(2,053)
Proceeds from the sale of capital assets	–	1,920	–
Purchased interest received	18	1,487	–
Interest paid on revenue bonds and other debt	(15,834)	(191,812)	(563)
Passenger facility charges	–	8,214	–
Acquisition and construction of capital assets	(22,223)	(350,572)	(10,853)
Contributions from municipality	–	–	2,475
Contributions from State and Federal governments	–	7,137	–
Contributions in aid of construction	2,127	20,799	–
Bond issuance costs	(8)	(2,659)	–
Bond discounts	(15)	(1,256)	–
Bond premiums	445	13,014	–
Bonds issued for advanced refundings of debt	4,205	313,882	–
Cash paid for bond refunding escrow	(4,627)	(326,742)	–
Cash paid for nuclear fuel inventory	–	(9,683)	–
Net cash provided (used) by capital and related financing activities	(42,708)	(542,283)	(10,994)

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

(Continued)

Proprietary Funds
Statement of Cash Flows
For the year ended September 30, 2003
(In thousands)

	Electric	Water and Wastewater	Airport
CASH FLOWS FROM INVESTING ACTIVITIES:			
Purchase of investment securities	$ (369,071)	(120,306)	(53,435)
Proceeds from sale and maturities of investment securities	339,770	118,579	52,039
Interest on investments	21,572	4,743	1,701
Net cash provided by investing activities	(7,729)	3,016	305
Net increase (decrease) in cash and cash equivalents	(109,619)	(62,874)	(6,105)
Cash and cash equivalents, October 1	201,474	115,373	89,746
Cash and cash equivalents, September 30	91,855	52,499	83,641
RECONCILIATION OF OPERATING INCOME TO NET CASH PROVIDED (USED) BY OPERATING ACTIVITIES:			
Operating income (loss)	277,657	82,469	6,731
Adjustments to reconcile operating income to net cash provided by operating activities:			
Depreciation	89,757	47,980	15,962
Amortization	–	2,500	–
Change in assets and liabilities:			
Increase in working capital advances	953	–	–
(Increase) decrease in accounts receivable	(27,193)	(14,135)	(2,585)
Increase (decrease) in allowance for doubtful accounts	(903)	71	–
Decrease in receivable from other governments	–	–	–
(Increase) decrease in inventory	3,423	(301)	–
(Increase) decrease in prepaid expenses and other assets	(65,726)	(17)	–
Decrease in deferred costs and other expenses	7,638	–	–
Decrease in other long-term assets	2,050	–	–
Increase (decrease) in accounts payable	4,754	(1,133)	(3,749)
Increase in accrued payroll and compensated absences	437	191	201
Decrease in claims payable	–	–	–
Increase (decrease) in deferred credits and other liabilities	(6,710)	(960)	2,589
Increase in customer deposits	1,992	664	151
Total adjustments	10,472	34,860	12,569
Net cash provided (used) by operating activities	$ 288,129	117,329	19,300

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

(Continued)

	Nonmajor Enterprise Funds	2003 Total	Governmental Activities- Internal Service Funds
CASH FLOWS FROM INVESTING ACTIVITIES:			
Purchase of investment securities	(36,031)	(578,843)	–
Proceeds from sale and maturities of investment securities	34,611	544,999	–
Interest on investments	2,444	30,460	435
Net cash provided by investing activities	1,024	(3,384)	435
Net increase (decrease) in cash and cash equivalents	(4,081)	(182,679)	(12,442)
Cash and cash equivalents, October 1	112,701	519,294	73,001
Cash and cash equivalents, September 30	108,620	336,615	60,559
RECONCILIATION OF OPERATING INCOME TO NET CASH PROVIDED (USED) BY OPERATING ACTIVITIES:			
Operating income (loss)	(10,784)	356,073	3,863
Adjustments to reconcile operating income to net cash provided by operating activities:			
Depreciation	12,801	166,500	1,697
Amortization	–	2,500	–
Change in assets and liabilities:			
Increase in working capital advances	–	953	–
(Increase) decrease in accounts receivable	336	(43,577)	(9,902)
Increase (decrease) in allowance for doubtful accounts	127	(705)	–
Decrease in receivable from other governments	417	417	–
(Increase) decrease in inventory	(2)	3,120	372
(Increase) decrease in prepaid expenses and other assets	21	(65,722)	(20)
Decrease in deferred costs and other expenses	–	7,638	–
Decrease in other long-term assets	–	2,050	–
Increase (decrease) in accounts payable	294	166	727
Increase in accrued payroll and compensated absences	228	1,057	305
Decrease in claims payable	–	–	1,367
Increase (decrease) in deferred credits and other liabilities	33	(5,048)	(168)
Increase in customer deposits	398	3,205	–
Total adjustments	14,653	72,554	(5,622)
Net cash provided (used) by operating activities	3,869	428,627	(1,759)

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

(Continued)

Proprietary Funds
Statement of Cash Flows
For the year ended September 30, 2003
(In thousands)

	Electric	Water and Wastewater	Airport
NONCASH INVESTING, CAPITAL AND FINANCING ACTIVITIES:			
Increase in advances from other funds	$ –	–	–
Increase in deferred assets/expenses	11,869	7,099	–
Increase (decrease) in capital appreciation bond interest payable	(1,579)	14,276	–
Capital assets contributed from (to) other funds	–	–	19
Increase in contributed facilities	–	13,514	–
Net decrease in the fair value of investments	(3,333)	(1,178)	–
Amortization of bond issue costs	(831)	(565)	(105)
Amortization of bond discounts and premiums	(1,613)	(674)	465
Amortization of deferred loss on refundings	12,914	5,639	74
Gain (loss) on disposal of assets	(13,594)	22	(181)
Deferred gain and loss on bond refunding	(72)	(23)	–
Bond issuance costs, discounts, premiums and accrued interest written off due to refunding	162	142	–
Deferred costs (recovered) to be recovered	11,982	(5,066)	–
Loss on extinguishment of debt	–	–	–
Contributions from other funds	–	–	–
Increase in deferred credits and other liabilities	5,842	21,082	–
Capital lease obligations	1,044	171	40
General obligation bonds and other tax supported debt proceeds receivable	960	270	–
Debt paid by other governmental entities	–	(513)	–

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

	Nonmajor Enterprise Funds	2003 Total	Governmental Activities- Internal Service Funds
NONCASH INVESTING, CAPITAL AND FINANCING ACTIVITIES:			
Increase in advances from other funds	–	–	42
Increase in deferred assets/expenses	–	18,968	–
Increase (decrease) in capital appreciation bond interest payable	–	12,697	–
Capital assets contributed from (to) other funds	8	27	(3,027)
Increase in contributed facilities	–	13,514	–
Net decrease in the fair value of investments	(13)	(4,524)	–
Amortization of bond issue costs	(173)	(1,674)	–
Amortization of bond discounts and premiums	89	(1,733)	(2)
Amortization of deferred loss on refundings	382	19,009	6
Gain (loss) on disposal of assets	(1,839)	(15,592)	21
Deferred gain and loss on bond refunding	(131)	(226)	–
Bond issue costs, discounts, premiums and accrued interest written off due to refunding	45	349	–
Deferred costs (recovered) to be recovered	(11)	6,905	–
Loss on extinguishment of debt	230	230	–
Contributions from other funds	(31)	(31)	144
Increase in deferred credits and other liabilities	–	26,924	–
Capital lease obligations	403	1,658	830
General obligation bonds and other tax supported debt proceeds receivable	3,800	5,030	9,090
Debt paid by other governmental entities	–	(513)	–

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

	Private Purpose Trust	Agency
ASSETS		
Pooled investments and cash	$ 884	2,297
Other assets	121	–
Total assets	1,005	2,297
LIABILITIES		
Accounts payable	1	51
Due to other governments	–	1,553
Deposits and other liabilities	253	693
Total liabilities	254	2,297
NET ASSETS		
Held in trust	751	
Total net assets	$ 751	

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

	Private Purpose Trust
ADDITIONS	
Contributions	$ 217
Interest and other	18
Total additions	235
DEDUCTIONS	
Deductions	157
Total deductions	157
Change in net assets	78
Total net assets - beginning	673
Total net assets - ending	$ 751

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

1 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The City of Austin, Texas (the City) is a municipal corporation incorporated under Article XI, Section 5 of the Constitution of the State of Texas (Home Rule Amendment). The City operates under a Council-Manager form of government. The City Council is composed of a Mayor and six Councilmembers, all of whom are elected at large for three-year staggered terms, and who may serve for a maximum of two consecutive terms. A petition signed by 5% of the voters waives the term limit for a councilmember.

The City's major activities or programs include public safety; transportation, planning and sustainability; public health; public recreation and culture; urban growth management and general government. In addition, the City owns and operates certain major enterprise activities, including an electric utility, water and wastewater utility, airport and other enterprise activities. These activities are included in the accompanying financial statements.

The Charter of the City of Austin requires an annual audit by an independent certified public accountant. The financial statements of the City have been prepared in conformity with accounting principles generally accepted in the United States of America as applied to governmental entities. The Governmental Accounting Standards Board (GASB) is the accepted standard-setting body for establishing governmental accounting and financial reporting principles. The City has implemented GASB Statement No. 1 through Statement No. 39 and Statement No. 41. GASB Statement No. 39 entitled *"Determining if Certain Organizations are Component Units"* was implemented in the City's fiscal year 2003, as required by GASB. There were no additional component units identified in the City's reporting structure as a result. GASB Statement No. 41 entitled *"Budgetary Comparison Schedules – Perspective Differences – an amendment to GASB Statement No. 34"*, does not alter the City's financial reporting presentation from previous years. The more significant accounting and reporting policies and practices used by the City are described below.

As a local government, the City is exempt from federal income taxes, under Internal Revenue Code Section 115, and state sales tax.

a – Reporting Entity

As required by generally accepted accounting principles (GAAP), these financial statements present the City (the Primary Government) and its component units, entities for which the City is considered to be financially accountable. Blended component units, although legally separate entities are, in substance, part of the City's operations and so data from these units are combined with data of the City.

Blended Component Units – The Austin Housing Finance Corporation (AHFC) and Austin Industrial Development Corporation (AIDC) are legally separate entities from the City. AHFC and AIDC serve all the citizens of Austin and are governed by a board composed of the City Councilmembers. The activities are reported in the Housing Assistance Fund and Austin Industrial Development Corporation Fund, nonmajor special revenue funds.

Related Organizations – The following entities are related organizations to which the City Council appoints board members, but for which the City has no significant financial accountability. The City appoints certain members of the board of the Capital Metropolitan Transit Authority (Capital Metro), but the City's accountability for this organization does not extend beyond making the appointments. City Councilmembers appoint themselves as members of the board of the Austin-Bergstrom International Airport (ABIA) Development Corporation; their function on this board is ministerial rather than substantive. The City Council appoints the members of the board of Austin-Bergstrom Landhost Enterprises, Inc., and Austin Convention Enterprises, Inc.; the functions of these boards are ministerial rather than substantive. The Mayor, with consent of the City Council, appoints the Board of Commissioners for the Urban Renewal Agency, whose primary responsibility is to oversee the implementation and compliance of Urban Renewal Plans adopted by the City Council. The City's presiding officer of the municipality governing body appoints the persons to serve as commissioners of the Austin Housing Authority. All of these entities are separate from the operating activities of the City. Related organizations are not included in the City's reporting entity.

The City retirement plans (described in Note 8) and the City of Austin Deferred Compensation Plan for City employees are not included in the City's reporting entity because the City does not exercise substantial control over the entities.

1 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES, continued

b – Government-wide and Fund Financial Statements

Government-wide and Fund Financial Statements – The basic financial statements include both government-wide and fund financial statements. The government-wide financial statements (i.e., the statement of net assets and the statement of activities) report information on all of the non-fiduciary activities of the primary government and its component units. Internal service fund asset and liability balances that are not eliminated in the statement of net assets are reported in the governmental activities column on the government-wide statements. Governmental activities, which normally are supported by taxes and intergovernmental revenues, are reported separately from business-type activities, which rely to a significant extent on fees and charges to external customers.

The statement of activities demonstrates the degree to which the direct expenses of a function or segment are offset by program revenues. Direct expenses are those that are clearly identifiable with a specific function or segment. Certain indirect costs are included in the program expenses of most business-type activities. Program revenues include 1) charges to customers who purchase, use or directly benefit from goods, services or privileges provided by a given function or segment and 2) grants and contributions that are restricted to meet the operational or capital requirements of a particular function or segment. Taxes and other items not properly included among program revenues are reported as general revenues.

The fund level statements focus on the governmental, proprietary and fiduciary funds. The accounts of the City are organized on the basis of funds. Each fund was established for the purpose of accounting for specific activities in accordance with applicable regulations, restrictions or limitations. Major funds are determined by criteria specified by GASB; the City has not elected to present additional major funds that do not meet the minimum criteria. Major individual governmental funds and major individual enterprise funds are reported as separate columns in the fund financial statements. All other funds are aggregated into governmental or enterprise nonmajor fund groupings.

The City's fiduciary funds are presented in the fund financial statements by type (private purpose and agency). By definition these assets are held for the benefit of a third party and cannot be used to address activities or obligations of the government, and are therefore not included in the government-wide statements. Reconciliation of the fund financial statements to the government-wide financial statements is provided in the financial statements to explain the differences created by the integrated approach of GASB 34.

c – Measurement Focus, Basis of Accounting and Financial Statement Presentation

The government-wide financial statements are reported using the flow of economic resources measurement focus and the accrual basis of accounting. Revenues are recorded when earned and expenses are recorded when a liability is incurred, regardless of the timing of related cash flows. Property taxes are recognized as revenues in the year for which they are levied. Grants and similar items are recognized as revenues as soon as all eligibility requirements have been met.

Governmental fund financial statements are reported using the current financial resources measurement focus and the modified accrual basis of accounting. This basis of accounting recognizes revenues in the accounting period in which they become susceptible to accrual, i.e. both measurable and available. Revenues, other than grants, are considered to be available when they are collectible, within the current period or soon enough thereafter to pay liabilities of the current period (defined by the City as collected within 60 days of year end). Revenues billed under a contractual agreement with another governmental entity, including federal and state grants, are recognized when billed and when all eligibility requirements of the provider have been met and are considered to be available if expected to be collected within one year. Expenditures generally are recorded when a liability is due. However, expenditures related to compensated absences and arbitrage are recorded to the extent they are normally expected to be liquidated with available financial resources. Debt service expenditures are recognized when payment is matured. The reported fund balance of governmental funds is considered a measure of available spendable resources.

Property taxes, sales taxes, franchise taxes, hotel occupancy taxes, vehicle rental taxes, EMS charges, Municipal Court fines and interest associated with the current fiscal period are all considered to be susceptible to accrual and so have been recognized as revenues of the current fiscal period. All other revenue items are considered to be measurable and available only when cash is received by the City.

1 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES, continued

The City reports the following major governmental fund:

General Fund: The primary operating fund of the City. It is used to account for all financial resources, except those required to be accounted for in another fund. It includes the following activities: public safety; transportation, planning and sustainability; public health; public recreation and culture; urban growth management; and general government.

Proprietary and fiduciary fund financial statements are accounted for on the economic resources measurement focus and the accrual basis of accounting. Proprietary funds distinguish operating revenues and expenses from nonoperating items. Operating revenues and expenses generally result from providing services in connection with a proprietary fund's principal ongoing operations, such as providing electric or water-wastewater services. Other revenues or expenses are nonoperating items.

The City reports the following major enterprise funds:

Electric Fund: Accounts for the activities of the City-owned electric utility, doing business as Austin Energy ™.

Water and Wastewater Fund: Accounts for the activities of the City-owned water and wastewater utility.

Airport Fund: Accounts for the operations of the Austin-Bergstrom International Airport (ABIA).

In addition, the City reports the following nonmajor governmental funds:

Special Revenue Funds account for the proceeds of specific revenue sources that are legally restricted to expenditures for specified purposes, including grant funds.

Debt Service Funds account for the accumulation of resources for, and the payment of, general long-term debt and HUD Section 108 loan principal, interest and related costs.

Capital Projects Funds account for financial resources for the acquisition or construction of major capital facilities (other than those reported within proprietary funds and private purpose funds) and funded primarily by general obligation debt, other tax supported debt, interest income and other intergovernmental revenues. A 1981 ordinance requires the establishment of a separate fund for each bond proposition approved in each bond election.

Permanent Funds account for resources that are legally restricted to the extent that only earnings and not principal may be used for purposes that support the City's programs. Permanent funds account for the public recreation and culture activity.

The City reports the following proprietary and fiduciary funds:

Enterprise Funds account for operations that are financed and operated in a manner similar to private business enterprises. Costs are financed or recovered primarily through user charges. The City has elected to follow GASB statements issued after November 30, 1989, rather than statements issued by the Financial Accounting Standards Board (FASB), in accordance with GASB Statement No. 20. The nonmajor enterprise funds account for the operations in a variety of areas: convention center, drainage, golf, hospital (both Brackenridge and Austin Women's Hospital), recreation activities, primary care clinics, solid waste and transportation.

Internal Service Funds account for the financing of goods or services provided by one City department or agency to other City departments or agencies or to other governmental units on a cost-reimbursement basis. These activities include, but are not limited to, capital projects management, employee health benefits, fleet services, information services, liability reserve (city-wide self insurance) services, supportive services, wireless communication services and workers' compensation coverage.

1 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES, continued

Fiduciary Funds account for assets held by the City in a trustee capacity or as an agent for individuals, private organizations or other governments:

Private-purpose trust funds account for all other trust arrangements under which principal and income benefit individuals, private organizations or other governments. Private-purpose trust funds account for various purposes: general government, transportation, public recreation and culture and urban growth management.

Agency funds account for net assets held on behalf of others and are purely custodial (assets equal liabilities).

d – Budget

The City Manager submits a proposed budget to the City Council no later than thirty days prior to the beginning of the new fiscal year. The City Council holds public hearings, modifies the City Manager's recommendations, and adopts a final budget no later than the twenty-seventh day of September. The City Council passes an appropriation ordinance and a tax levying ordinance.

Annual budgets are legally adopted for the General Fund, certain special revenue funds and debt service funds. Annual budgets are adopted for enterprise and internal service funds, although they are not legally required. Multi-year budgets are adopted for capital projects and grant funds, where appropriations remain authorized for the life of the project, irrespective of fiscal year. Expenditures are appropriated on a modified accrual basis, except that commitments related to purchase orders are treated as expenditures in the year of commitment. Certain charges to ending fund balance are budgeted as nondepartmental expenditures.

Formal budgetary control is employed during the year at the fund and department level as a management control device for annually budgeted funds.

Budgets are modified throughout the year. The City Manager is authorized to transfer appropriation balances within a fund and department of the City. The City Council must approve amendments to the budget and transfers of appropriations from one fund and department to another. The original and final budgets for the General Fund are reported in the required supplementary information. Unencumbered appropriations for annual budgets lapse at fiscal year end.

During fiscal year 2003, the following nonmajor governmental funds exceeded their legally adopted expenditure or transfer budget (in thousands): Police Federal Seized Fund ($9) and Wildland Conservation ($44).

e – Financial Statement Elements

Pooled Investments and Cash – Cash balances of all City funds (except for certain funds shown in Note 5 as having non-pooled investments) are pooled and invested. Investments purchased with pooled cash, consisting primarily of U.S. government obligations and U.S. agency obligations, are stated at fair value. Interest earned on investments purchased with pooled cash is allocated monthly to each participating fund based upon the fund's average daily balance. Funds that incur a negative balance in pooled cash and investments are not allocated interest earnings nor charged interest expense.

Investments – Certain investments are required to be reported at fair value, based on quoted market prices. Realized gains or losses resulting from the sale of investments are determined by the specific cost of the securities sold. The City carries all of its investments in U.S. government and agency debt securities and money market mutual funds at fair value as of September 30, 2003. Investments in local government investment pools are carried at amortized cost, which approximates fair value.

1 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES, continued

Accounts Receivable – Balances of accounts receivable, reported on the government-wide statement of net assets, are aggregations of different components such as charges for services, fines, and balances due from taxpayers or other governments. In order to assist the reader, the following information has been provided regarding significant components of receivable balances as of September 30, 2003 (in thousands):

	Charges for Services	Fines	Taxes	Other Governments	Other	Total
Governmental activities						
General Fund	$ 56,263	53,407	25,730	–	–	135,400
Nonmajor governmental funds	2,935	21	7,339	15,886	70,789	96,970
Internal service funds	1,554	–	–	–	9,090	10,644
Allowance for doubtful accounts	(52,634)	(35,930)	–	–	–	(88,564)
Total	$ 8,118	17,498	33,069	15,886	79,879	154,450

Municipal Court fines in the governmental activities, because of the nature of the fines, have a collection period greater than one year. Fines recognized that will not be collected during the subsequent year are estimated to be approximately $8.5 million.

Business-type activities are primarily comprised of charges for services.

Elimination of Internal Activities – The elimination of internal service fund activity is needed in order to eliminate duplicate activity in making the transition from the fund level financial statements to the government-wide financial statements. In addition, the elimination of internal service fund activity requires the City to "look back" and adjust the internal service funds' internal charges. A positive change in net assets derived from internal service fund activity results in a pro rata reduction in the charges made to the participatory funds. A deficit change in net assets of internal service funds requires a pro rata increase in the amounts charged to the participatory funds.

Internal Balances – In the government-wide statement of net assets, internal balances are the receivables and payables between the governmental and business-type activities.

Interfund Activities – In the government-wide statement of activities, the effect of interfund activity has generally been removed from the statements. Exceptions include the chargeback of services, such as utilities or vehicle maintenance, and charges for central administrative costs. Elimination of these charges would distort the direct costs and program revenues of the various functions reported. The City recovers indirect costs that are incurred in the Support Services Fund, which is reported as an internal service fund. Indirect costs are calculated in a city-wide cost allocation plan or through indirect cost rates. These amounts are eliminated in the government-wide statement of activities.

Interfund Receivables, Payables – During the course of operations, numerous transactions occur between individual funds for goods provided or services rendered. These receivables and payables are classified as "due from other funds" or "due to other funds" on the fund-level statements when they are expected to be liquidated within one year. If receivables or payables are expected to be liquidated after one year, they are classified as "advances to other funds" or "advances from other funds."

Inventories – Inventories are valued at cost, which is determined as follows:

Fund	Inventory Valuation Method
General Fund	Average cost (predominantly); some first-in, first-out
Electric:	
Fuel oil and coal	Last-in, first out
Other inventories	Average cost
All others	Average cost

Inventories for all funds use the consumption method and expenditures are recorded when issued. Inventories reported in the General Fund and certain special revenue funds are offset by a fund balance reserve, which indicates that they do not represent "available spendable resources."

1 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES, continued

Restricted assets – Restricted assets are assets whose use is subject to constraints that are either (a) externally imposed by creditors (such as through debt covenants), grantors, contributors, or laws or regulations of other governments or (b) imposed by law through constitutional provisions or enabling legislation.

The balance of restricted assets accounts in the enterprise funds are as follows (in thousands):

	Electric	Water and Wastewater	Airport	Nonmajor Enterprise	Total Restricted Assets
Bond reserve	$ 64,396	45,652	–	6,757	116,805
Capital projects	17,158	30,123	66,986	58,027	172,294
Customer and escrow deposits	7,533	2,557	571	1,639	12,300
Debt service	90,385	45,159	21,921	7,355	164,820
Federal grants	–	–	4,962	–	4,962
Nuclear decommissioning	90,687	–	–	–	90,687
Nuclear fuel inventory replacement	29,531	–	–	–	29,531
Operating reserve account	–	–	–	1,957	1,957
Passenger facility charge account	–	–	9,348	–	9,348
Renewal and replacement account	–	–	10,000	1,330	11,330
	$ 299,690	123,491	113,788	77,065	614,034

Designated assets – Designated assets are funds that have been appropriated by City Council action and are intended for specific purposes. They are not constrained by creditors, grantors, contributors, or laws or regulations of other governments nor are they constrained by law through constitutional provisions or enabling legislation.

Capital assets – Capital assets, which include land and improvements, buildings and improvements, equipment, vehicles and infrastructure assets, are reported in the applicable governmental or business-type activity columns of the government-wide statement of net assets, and related depreciation is allocated to programs in the statement of activities. Capital assets are defined as assets with an initial individual cost of $1,000 or more and an estimated useful life of greater than one year. Assets purchased or constructed are capitalized at historical cost. Contributed or annexed capital assets are recorded at estimated fair market value at the time received, or at historical cost, if historical cost is available. Capital outlay is recorded as an expenditure in the General Fund and other governmental funds, and as an asset in the government-wide financial statements and proprietary funds. Maintenance and repairs are charged to operations as incurred, and improvements and betterments that extend the useful lives of capital assets are capitalized.

The City obtains public domain capital assets (infrastructure) through capital improvement projects (CIP) construction, or through annexation or developer contribution. Infrastructure consists of certain improvements other than buildings, including streets and roads, bridges, pedestrian facilities, drainage systems and traffic signal systems.

Interest is not capitalized on governmental capital assets. For enterprise funds, interest paid on long-term debt in the enterprise funds is capitalized when it can be attributed to a specific project and when it materially exceeds the interest revenue generated by the bond proceeds issued to fund the project.

1 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES, continued

Capital assets are depreciated using the straight-line method over the following estimated useful lives (in years):

		Business-type Activities			
Assets	Governmental Activities (1)	Electric	Water and Wastewater	Airport	Nonmajor Enterprise
Buildings	15-40	30-40	40-50	15-40	15-40
Equipment	7-30	7-40	10-50	10-50	7-40
Vehicles	3-20	3-15	3-20	3-15	3-15
Communication equipment	7	7	7	7	7
Furniture and fixtures	12	12	12	12	7-12
Computers and EDP equipment	3-7	3-7	3-7	3-7	3-7
Infrastructure					
Streets and roads	30	–	–	–	–
Bridges	50	–	–	–	–
Drainage systems	50	–	–	–	–
Pedestrian facilities	20	–	–	–	–
Traffic signals	25	–	–	–	–

(1) Includes internal service funds

Depreciation of assets is classified by functional components. The City considers land, arts and treasures and library collections to be inexhaustible; and therefore, these assets are reported as nondepreciable. The true value of arts and treasures and library collections is expected to be maintained over time and, thus, is not depreciated. Unallocated depreciation reported in the government-wide statement of activities consists of depreciation of infrastructure assets ($35.4 million).

The City Council approved a resolution directing the City Manager to include the closure of Holly Power Plant Units 3 and 4 by December 31, 2007 in the Strategic Plan developed by Austin Energy. Depreciation was accelerated on Holly Plant assets to coincide with this closure date. The resulting change increased depreciation expense by $1.2 million.

In the government-wide and proprietary fund statements, the City recognizes a gain or loss on the disposal of assets when it retires or otherwise disposes of capital assets (other than debt-financed assets of the utility funds, where the gain or loss is deferred in accordance with FASB Statement No. 71).

Intangible Assets – Proprietary Funds - Intangible assets include the amortized cost of a $100 million contract between the City and the Lower Colorado River Authority (LCRA) for a fifty-year assured water supply agreement, with an option to extend another fifty years. The City and LCRA entered into the contract in 1999, and the asset is being amortized over 40 years.

Deferred Expenses or Credits – The City's utility systems are reported in accordance with Financial Accounting Standards Board (FASB) Statement No. 71, *"Accounting for the Effects of Certain Types of Regulation"*. Certain utility expenses that do not currently require funds are deferred to future periods in which they are intended to be recovered by rates. Likewise, certain credits to income are deferred to periods in which they are matched with related costs. These expenses or credits include changes in fair value of investments, contributions and gain or loss on disposition of debt-financed assets. Deferred expenses will be recovered in these future periods by setting rates sufficient to provide funds for the related debt service requirements. If rates being charged will not recover deferred expenses, the deferred expenses will be subject to write off. Retail deregulation of electric rates in the future may affect the City's current accounting treatment of its electric utility revenues, expenses and deferred amounts.

Compensated Absences – The amounts owed to employees for unpaid vacation and sick leave liabilities, including the City's share of employment-related taxes, are reported on the accrual basis of accounting in the applicable governmental or business-type activity columns of the government-wide statements, and in the enterprise activities of the fund financial statements. The liabilities and expenditures are reported on the modified accrual basis in the governmental fund financial statements; the estimated liability for governmental funds is the amount of sick and vacation paid at termination within 60 days of year-end.

1 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES, continued

City policies provide for the following amounts to be paid at termination: accumulated vacation pay with a maximum of six weeks and accumulated sick leave with a maximum of ninety days. Sick leave accumulated in excess of ninety days or by employees hired on or after October 1, 1986 is not payable at termination, and is not included in these financial statements.

Long-Term Debt – The debt service for general obligation bonds and other general obligation debt, including loans, issued to fund general government capital projects is paid from tax revenues, interfund transfers and intergovernmental revenues. Such general obligation debt is reported in the government-wide statements under governmental activities.

The debt service for general obligation bonds and other general obligation debt issued to fund proprietary fund capital projects is normally paid from net revenues of the applicable proprietary fund, although such debt will be repaid from tax revenues if necessary. Such general obligation debt is shown as a specific liability of the applicable proprietary fund, which is appropriate under generally accepted accounting principles and in view of the expectation that the proprietary fund will provide resources to service the debt.

Revenue bonds that have been issued to finance capital projects of certain enterprise funds are to be repaid from net revenues of these funds. Such debt is recorded in the funds. Operating revenues and interest income that are used as security for revenue bonds are reported separately from other revenues.

The City has certain contractual commitments with several municipal utility districts (MUDs) for the construction of additions and improvements to the City's water and wastewater system that serve the MUDs and surrounding areas. These additions and improvements are funded by City contract revenue bonds, whose principal and interest are payable primarily from the net revenues of the Water and Wastewater Fund.

The City defers and amortizes gains or losses realized by proprietary funds on refundings of debt and for governmental activities in the government-wide financial statements, and reports both the new debt liability and the related deferred amount on the funds' balance sheets. The City recognizes gains or losses on debt defeasance when funds from current operations are used.

Other Long-Term Liabilities – Capital appreciation bonds are recorded at net accreted value. Annual accretion of the bonds is recorded as interest expense during the life of the bonds. The cumulative accretion of capital appreciation bonds, net of interest payments on the bonds, is recorded as capital appreciation bond interest payable.

Landfill Closure and Postclosure Care Costs – The City reports municipal solid waste landfill costs in accordance with GASB Statement No. 18, *"Accounting for Municipal Solid Waste Landfill Closure and Postclosure Care Costs"*. The liability for landfill closure and postclosure costs is reported in the Solid Waste Services Fund, a nonmajor enterprise fund.

Operating Revenues – Revenues are recorded net of allowances, including bad debt, in the government-wide and proprietary fund-level statements. The funds listed below reduced revenues by bad debt expense, as follows (in thousands):

Electric Fund	$ 7,769
Water and Wastewater Fund	1,108
Nonmajor Enterprise Funds	1,352

Electric, water and wastewater revenue is recorded when earned in 2003 and when billed in 2002 and prior years. Customers' electric and water meters are read and bills are rendered on a cycle basis by billing district. Electric rate schedules include fuel cost adjustment clauses that permit recovery of fuel costs in the month incurred. The City reported fuel costs on the same basis as it recognized revenue in 2002 and prior years. In 2003, Austin Energy recorded unbilled revenue as earned based upon taking each day's power generation and using the billing district read dates to estimate what percentage was billed as of September 30, 2003 and what percentage will be billed thereafter over the days since the last meter read, on a billing cycle basis. The amount of unbilled revenue recorded as of September 30, 2003 for the Electric Fund was $35.8 million. The Water and Wastewater Fund recorded unbilled revenue as earned based upon an extrapolation of customer usage from the prior year, over the days since the last meter read, on an aggregate basis. The amount of unbilled revenue recorded as of September 30, 2003 for the Water and Wastewater Fund was $14.4 million.

1 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES, continued

Federal and State Grants, Entitlements and Shared Revenues – Grants, entitlements and shared revenues may be accounted for within any City fund. The purpose and requirements of each grant, entitlement, or shared revenue are analyzed to determine the appropriate fund statement and revenue category in which to report the related transactions. Grants, entitlements and shared revenues received for activities normally recorded in a particular fund may be accounted for in that fund, provided that applicable legal restrictions can be satisfied.

Revenues received for activities normally recorded in other governmental funds are accounted for within the nonmajor governmental fund groupings: Federal grant funds, State grant funds, and other special revenue grant funds. Capital grants restricted for capital acquisitions or construction, other than those associated with proprietary type funds, are accounted for in the applicable capital projects funds. Revenues received for operating activities of proprietary funds or revenues that may be used for either operations or capital expenditures at the discretion of the City are recognized in the applicable proprietary fund.

Restricted Resources – When both restricted and unrestricted resources are available for use, it is the City's policy to use restricted resources first and then unrestricted resources as they are needed.

Reservations of Fund Equity – Reservation of fund balances of the governmental funds indicate that portion of fund equity which is not available for appropriation for expenditure or is legally restricted by outside parties for use for a specific purpose. Designations of fund balance are the representations of management for the utilization of resources in future periods.

Cash and Cash Equivalents – For purposes of the statement of cash flows, the City considers cash and cash equivalents to be currency on hand, cash held by trustee, demand deposits with banks, and all amounts included in pooled investments and cash accounts.

Pension Costs – It is the policy of the City to fund pension costs annually. Pension costs are composed of normal cost and, where applicable, amortization of unfunded actuarial accrued liability and of unfunded prior service cost (see Note 8).

Risk Management – The City is exposed to employee-related risks for health benefits and workers' compensation, as well as to various risks of loss related to torts, including medical malpractice; theft of, damage to, or destruction of assets; errors and omissions; and natural disasters. The City continues to be self-insured for liabilities for most health benefits, third-party and workers' compensation claims.

The City purchases commercial insurance for coverage for property loss or damage, commercial crime, fidelity bonds, and airport operations. In addition, the City purchases a broad range of insurance coverage for contractors working at selected capital improvement project sites. The City does not participate in a risk pool. The City complies with GASB Statement No. 10, *"Accounting and Reporting for Risk Financing and Related Insurance Issues"* (see Note 14).

Austin Energy initiated the energy risk management pilot program. This program was authorized by City Council and led by the Risk Oversight Committee. Under this program, Austin Energy enters into futures contracts, options, and swaps for the purpose of reducing exposure to natural gas and energy price risk. The City complies with GASB Technical Bulletin No. 2003-1, *"Disclosure Requirements for Derivatives Not Reported at Fair Value on the Statement of Net Assets"* (see Note 14).

f – Comparative Data

Governments are required to present comparative data only in connection with Management's Discussion and Analysis (MD&A). Comparative data has been utilized within the MD&A to more fully understand the City's financial statements for the current period.

g – 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 financial statements and the reported amounts of revenues and expenditures during the reporting period. Actual results could differ from those estimates.

2 – RECONCILIATION OF GOVERNMENT-WIDE AND FUND FINANCIAL STATEMENTS

a – Explanation of differences between the governmental fund balance sheet and the government-wide statement of net assets

Total fund balances of the City's governmental funds, $345 million, differ from the net assets of governmental activities, $1,348 million, reported in the statement of net assets. The differences result from the long-term economic focus in the government-wide statement of net assets versus the current financial resources focus of the governmental fund balance sheets. The differences are shown below (in thousands):

Total fund balances - Governmental funds		$ 345,455
Amounts reported for governmental activities in the statement of net assets are different because:		
Capital assets used in governmental activities are not financial resources and therefore are not reported in the funds.		
Governmental capital assets	2,356,163	
Less: accumulated depreciation	(527,045)	
Total		1,829,118
Other-long term assets are not available as current-period resources and are not reported in the funds.		
Accounts and other taxes receivable	18,351	
Deferred revenue - Property taxes/interest	266	
Total		18,617
Long-term liabilities are not payable in the current period and are not reported in the funds.		
Bonds and other tax supported debt payable, net	(811,736)	
Capital lease obligations payable	(356)	
Compensated absences	(61,814)	
Interest payable	(3,843)	
Deferred credits and other liabilities	(8,970)	
Total		(886,719)
Internal service funds		41,656
Total net assets - Governmental activities		$ 1,348,127

2 – RECONCILIATION OF GOVERNMENT-WIDE AND FUND FINANCIAL STATEMENTS, continued

b – Explanation of differences between the governmental fund statement of revenues, expenditures, and changes in fund balances and the government-wide statement of activities

The net change in fund balances of governmental funds, $38 million deficit, differs from the change in net assets for governmental activities, $100.7 million, reported in the statement of activities. The differences result from the long-term economic focus in the government-wide statement of net assets versus the current financial resources focus of the governmental fund balance sheets. The differences are shown below (in thousands):

Net change in fund balances - Governmental funds		$ (37,950)
Governmental funds report capital outlay as expenditures. In the statement of activities, the cost of those assets are depreciated over the estimated useful life of the asset.		
Capital outlay	160,821	
Depreciation expense	(56,033)	
Loss on disposal of capital assets	(602)	
Total		104,186
Revenues in the statement of activities that do not provide current available financial resources are not reported as revenues in the funds.		
Property taxes	32	
Franchise fees and gross receipts tax	(1)	
Charges for services	68	
Interest and other	(228)	
Capital assets contribution	71,964	
Total		71,835
Revenues in the governmental funds are recognized when measurable and available, but are deferred in the statement of activities until earned, regardless of when collected.		
Intergovernmental revenue	(14,957)	
Total		(14,957)
Costs associated with the issuance of long-term debt are reported as expenditures in the governmental funds, but are deferred and amortized throughout the period during which the related debt is outstanding in the statement of activities. Repayment of debt principal is an expenditure in the governmental funds, but the repayment reduces long-term liabilities in the statement of net assets.		
Issuance of long-term debt	(70,323)	
Principal repayment on long-term debt	49,340	
Total		(20,983)
Some expenses reported in the statement of activities do not require the use of current financial resources and therefore are not reported as expenditures in governmental funds.		
Compensated absences	(5,103)	
Interest and other	(146)	
Total		(5,249)
Internal services. The net revenue (expense) of the internal service funds is reported with the governmental activities.		3,808
Change in net assets - Governmental activities		$ 100,690

3 – DEFICITS IN FUND BALANCES AND NET ASSETS

At September 30, 2003, the following funds reported deficits in fund balances or net assets. Management intends to recover these deficits through future operating revenues, transfers or debt issues.

Nonmajor Governmental	Deficit (in thousands)	Internal Service Funds:	Deficit (in thousands)
Special Revenue Funds:			
Tourism and Promotion	$ 21	Liability Reserve	$ 6,043
Capital Projects Funds:			
Energy improvements - city facilities	82		
Parks/Old Bakery	179		
Police facilities	14		
Transportation Mobility Improvements	82		
Parks - 1992	173		
Build Austin	25		
Public Works	21		
Conservation Land	1		

The City Council passed a resolution to reimburse the deficit in the Transportation Mobility Improvements Fund through a future bond sale. The Liability Reserve deficit will be recovered through future transfers.

4 – POOLED INVESTMENTS AND CASH

The following summarizes the amounts of pooled investments and cash by fund at September 30, 2003 (in thousands):

	Pooled Investments and Cash	
	Unrestricted	Restricted
General Fund	$ 84,451	–
Nonmajor governmental funds	167,045	–
Electric	35,345	52,065
Water and Wastewater	19,137	27,769
Airport	1,915	81,721
Nonmajor enterprise funds	49,450	59,153
Internal service funds	60,053	–
Fiduciary funds	3,181	–
Subtotal pooled investments and cash	420,577	220,708
Total pooled investments and cash	$ 641,285	

5 – INVESTMENTS AND DEPOSITS

a – Investments

The City's deposits and investments are invested pursuant to the City of Austin Investment Policy, which is approved annually by the City Council. The objective of the policy is, in order of priority, preservation of capital, liquidity and yield. The policy addresses the soundness of financial institutions in which the City will deposit funds, types of investment instruments and the percentage of the portfolio that may be invested in certain instruments with longer terms to maturity.

5 – INVESTMENTS AND DEPOSITS, continued

Chapter 2256, Texas Government Code (The Public Funds Investment Act) and the City of Austin Investment Policy authorize the City to invest in the following:

(1) Obligations of the U.S. Treasury;
(2) Federal Agencies;
(3) Direct obligations of The State of Texas;
(4) Other States, Cities, Counties or Other Political Subdivisions;
(5) Local Government Investment Pools;
(6) Repurchase Agreements;
(7) Reverse Repurchase Agreements;
(8) Bankers' Acceptances;
(9) Commercial Paper;
(10) Money Market Mutual Funds;
(11) Certificates of deposit; and
(12) Share certificates issued by State or Federal Credit Unions.

The City participates in two Texas local government investment pools: TexPool and TexasTERM/Daily. The State Comptroller of Public Accounts oversees TexPool, with Lehman Brothers and Federated Investors managing the daily operations of the pool under a contract with the Comptroller. An advisory board, consisting of participants or their designees, maintains oversight responsibility for TexasTERM/Daily. The fair value of the City's position in these pools is equivalent to the carrying value.

The City did not participate in any reverse repurchase agreements during fiscal year 2003.

The City's investments (with exceptions noted below) are categorized below to give an indication of the level of custodial risk assumed by the City at year-end.

- Category 1 investments are insured or registered or the City's agent holds the securities in the City's name.
- Category 2 investments are uninsured and unregistered investments and the securities are held by the counterparty's trust department or agent in the City's name.
- Category 3 investments are uninsured and unregistered investments and the securities are held by the counterparty's trust department or agent, but not in the City's name.

	Category			Fair Value
	1	2	3	(in thousands)
Investments				
Obligations of the U.S. government and its agencies	$ 810,447	–	–	810,447
	810,447	–	–	810,447
Investments held by trustee				
Obligations of the U.S. government and its agencies	92,783	–	–	92,783
Investments not categorized				
TexPool, Texas Local Government Investment Pool				258,665
TexasTERM/Daily, Local Government Investment Pool				88,021
				346,686
Total investments				$ 1,249,916

5 – INVESTMENTS AND DEPOSITS, continued

Investments and deposits at September 30, 2003 are as follows (in thousands):

	Governmental Activities	Business-type Activities	Fiduciary Funds	Total
Non-pooled investments and deposits	$ 25,076	599,740	–	624,816
Pooled investments and deposits	316,314	331,544	3,181	651,039
Total investments and deposits	341,390	931,284	3,181	1,275,855
Unrestricted deposits	10,391	51	–	10,442
Restricted deposits	–	10,009	–	10,009
Pooled deposits	2,666	2,795	27	5,488
Investments	328,333	918,429	3,154	1,249,916
Total investments and deposits	$ 341,390	931,284	3,181	1,275,855

A difference of $9.8 million exists between bank balance and book balance, primarily due to deposits in transit offset by outstanding checks.

b – Deposits

The September 30, 2003, carrying amount of deposits is as follows (in thousands):

	Governmental Activities	Business-type Activities	Fiduciary Funds	Total
Cash				
Unrestricted	$ 112	51	–	163
Cash held by trustee				
Unrestricted	10,279	–	–	10,279
Restricted	–	10,009	–	10,009
Pooled cash	2,666	2,795	27	5,488
Total deposits	$ 13,057	12,855	27	25,939

All bank balances were either insured or collateralized with securities held by the City or by its agent in the City's name at September 30, 2003.

6 – PROPERTY TAXES

The City's property tax is levied each October 1 on the assessed value listed as of January 1 for all real and personal property located in the City. The adjusted assessed value for the roll as of January 1, 2002, upon which the 2003 levy was based, was $50,759,650,668.

Taxes are due by January 31 following the October 1 levy date. During the year ended September 30, 2003, 98.84% of the current tax levy (October 1, 2002) was collected. The statutory lien date is January 1.

The methods of property assessment and tax collection are determined by Texas statute. The statutes provide for a property tax code, county-wide appraisal districts, a State property tax board, and certain exemptions from taxation, such as intangible personal property, household goods, and family-owned automobiles.

6 – PROPERTY TAXES, continued

The appraisal of property within the City is the responsibility of the Travis Central Appraisal District and the Williamson County Appraisal District. The appraisal districts are required under the Property Tax Code to assess all real and personal property within the appraisal district on the basis of 100% of its appraised value and are prohibited from applying any assessment ratios. The value of property within the appraisal district must be reviewed every three years; however, the City may require more frequent reviews of appraised values at its own expense. The Travis Central Appraisal District has chosen to review the value of property every two years, while the Williamson County Appraisal District has chosen to review the value of property on an annual basis. The City may challenge appraised values established by the appraisal district through various appeals and, if necessary, legal action.

The City is authorized to set tax rates on property within the City limits. However, if the effective tax rate, excluding tax rates for bonds, certificates of obligation, and other contractual obligations, as adjusted for new improvements and revaluation, exceeds the rate for the previous year by more than 8%, State statute allows qualified voters of the City to petition for an election to determine whether to limit the tax rate increase to no more than 8%.

The City is permitted by Article II, Section 5 of the State of Texas Constitution to levy taxes up to $2.50 per $100 of assessed valuation for general governmental services, including the payment of principal and interest on general obligation long-term debt. Under the City Charter, a limit on taxes levied for general governmental services, exclusive of payments of principal and interest on general obligation long-term debt, has been established at $1.00 per $100 assessed valuation. A practical limitation on taxes levied for debt service of $1.50 per $100 of assessed valuation is established by State Statute and City Charter limitations. Through contractual arrangements, Travis and Williamson counties bill and collect property taxes for the City.

The tax rate to finance general governmental functions, other than the payment of principal and interest on general obligation long-term debt, for the year ended September 30, 2003, was $.2969 per $100 assessed valuation. The City has a tax margin for general governmental purposes of $.7031 per $100 assessed valuation, and could levy approximately $356,891,104 in additional taxes from the assessed valuation of $50,759,650,668 before the legislative limit is reached.

The City has reserved a portion of the taxes collected for lawsuits filed by certain tax payers against the appraisal districts challenging assessed values.

7 – CAPITAL ASSETS AND INFRASTRUCTURE

The City anticipates the need for numerous additional utility-related projects over the next several years. However, specific projects and related funding have not been identified or authorized.

The City is accelerating the depreciation of two generating stations that will be retired before the end of their estimated useful lives. The increase to the Electric Fund 2003 depreciation expense for this accelerated depreciation is $1,210,000.

The City has recorded capitalized interest for fiscal year 2003 in the following funds related to the construction of various enterprise fund capital improvement projects (in thousands):

Major fund:		
	Airport	$ 685
Nonmajor enterprise funds:		
	Convention Center	1,052
	Drainage	458
	Golf	94
	Solid Waste Services	210

7 – CAPITAL ASSETS AND INFRASTRUCTURE, continued

Components of capital assets (in thousands)

	Governmental Activities	Business-type Activities	Total
Capital assets not depreciated			
Land and improvements	$ 195,274	270,600	465,874
Arts and treasures	4,785	727	5,512
Library collections	12,880	–	12,880
Total	212,939	271,327	484,266
Property, plant and equipment in service			
Building and improvements	310,174	1,862,542	2,172,716
Equipment	50,253	3,848,527	3,898,780
Vehicles	74,447	84,419	158,866
Infrastructure	1,308,273	–	1,308,273
Completed assets not classified	108,595	328,437	437,032
Total	1,851,742	6,123,925	7,975,667
Less accumulated depreciation for			
Building and improvements	(84,558)	(507,997)	(592,555)
Equipment	(23,938)	(1,578,768)	(1,602,706)
Vehicles	(38,791)	(48,343)	(87,134)
Infrastructure	(389,336)	–	(389,336)
Completed assets not classified	(13,299)	(8,616)	(21,915)
Total	(549,922)	(2,143,724)	(2,693,646)
Net property, plant and equipment in service	1,301,820	3,980,201	5,282,021
Construction in progress	353,951	661,157	1,015,108
Nuclear fuel, net of amortization	–	21,805	21,805
Plant held for future use	–	31,379	31,379
Total capital assets	$ 1,868,710	4,965,869	6,834,579

7 – CAPITAL ASSETS AND INFRASTRUCTURE, continued

Governmental Activities

Capital asset activity for the year ended September 30, 2003 was as follows (in thousands):

	Beginning Balance	Increases	Decreases	Ending Balance
Capital assets not depreciated				
Land and improvements	$ 151,314	43,960	–	195,274
Arts and treasures	4,450	335	–	4,785
Library collections	12,706	174	–	12,880
Total	168,470	44,469	–	212,939
Property, plant and equipment in service				
Building and improvements	265,028	45,742	(596)	310,174
Equipment	46,331	13,802	(9,880)	50,253
Vehicles	69,496	9,795	(4,844)	74,447
Infrastructure	1,218,959	89,314	–	1,308,273
Completed assets not classified	202,908	160	(94,473)	108,595
Total	1,802,722	158,813	(109,793)	1,851,742
Less accumulated depreciation for				
Building and improvements	(75,765)	(9,384)	591	(84,558)
Equipment	(29,301)	(4,227)	9,590	(23,938)
Vehicles	(35,751)	(7,250)	4,210	(38,791)
Infrastructure	(352,467)	(36,869)	–	(389,336)
Completed assets not classified	(13,299)	–	–	(13,299)
Total	(506,583)	(57,730)	14,391	(549,922)
Net property, plant and equipment in service	1,296,139	101,083	(95,402)	1,301,820
Construction in progress	223,455	155,612	(25,116)	353,951
Total capital assets	$ 1,688,064	301,164	(120,518)	1,868,710

Depreciation expense was charged to functions as follows (in thousands):

Governmental activities:	
General government	$ 891
Public safety	8,720
Transportation, planning and sustainability	3,387
Public health	871
Public recreation and culture	5,433
Urban growth management	1,317
Unallocated depreciation expense - infrastructure	35,414
Internal service funds	1,697
Total governmental activities depreciation expense	$ 57,730

7 – CAPITAL ASSETS AND INFRASTRUCTURE, continued

Business-type Activities: Electric Fund

Capital asset activity for the year ended September 30, 2003 was as follows (in thousands):

	Beginning Balance	Increases	Decreases	Ending Balance
Capital assets not depreciated				
Land and improvements	$ 32,877	2,065	–	34,942
Total	32,877	2,065	–	34,942
Property, plant and equipment in service				
Building and improvements	566,795	36,380	(1,382)	601,793
Equipment	2,208,322	115,841	(21,483)	2,302,680
Vehicles	19,367	1,305	(1,353)	19,319
Completed assets not classified	194,004	23,899	(190,286)	27,617
Total	2,988,488	177,425	(214,504)	2,951,409
Less accumulated depreciation for				
Building and improvements	(233,771)	(16,925)	140	(250,556)
Equipment	(951,540)	(72,010)	3,243	(1,020,307)
Vehicles	(15,443)	(822)	1,346	(14,919)
Completed assets not classified	(3,232)	–	339	(2,893)
Total	(1,203,986)	(89,757)	5,068	(1,288,675)
Net property, plant and equipment in service	1,784,502	87,668	(209,436)	1,662,734
Construction in progress	160,485	365,039	(165,775)	359,749
Nuclear fuel, net of amortization	18,102	3,703	–	21,805
Plant held for future use	31,379	–	–	31,379
Total capital assets	$ 2,027,345	458,475	(375,211)	2,110,609

7 – CAPITAL ASSETS AND INFRASTRUCTURE, continued

Business-type Activities: Water and Wastewater Fund

Capital asset activity for the year ended September 30, 2003 was as follows (in thousands):

	Beginning Balance	Increases	Decreases	Ending Balance
Capital assets not depreciated				
Land and improvements	$ 135,325	848	–	136,173
Total	135,325	848	–	136,173
Property, plant and equipment in service				
Building and improvements	1,356,114	10,675	(1,022,915) (1)	343,874
Equipment	452,012	1,061,750 (1)	(5,381)	1,508,381
Vehicles	21,203	514	(729)	20,988
Completed assets not classified	275,535	122	(27,244)	248,413
Total	2,104,864	1,073,061	(1,056,269)	2,121,656
Less accumulated depreciation for				
Building and improvements	(444,518)	(7,671)	348,609 (1)	(103,580)
Equipment	(154,423)	(387,202) (1)	5,272	(536,353)
Vehicles	(12,971)	(1,366)	726	(13,611)
Completed assets not classified	(4,640)	–	–	(4,640)
Total	(616,552)	(396,239) (2)	354,607	(658,184)
Net property, plant and equipment in service	1,488,312	676,822	(701,662)	1,463,472
Construction in progress	104,100	129,101	(1,031)	232,170
Total capital assets	$ 1,727,737	806,771	(702,693)	1,831,815

(1) The City implemented a fixed asset accounting system. During the implementation process, asset categories were reviewed and $1,022,565 of buildings and improvements were reclassified to equipment and $348,259 of accumulated depreciation - buildings and improvements was reclassifed to accumulated depreciation - equipment.

(2) Components of accumulated depreciation increases:

Current year depreciation	$ 47,980
Reclassification	348,259
	$ 396,239

7 – CAPITAL ASSETS AND INFRASTRUCTURE, continued

Business-type Activities: Airport Fund

Capital asset activity for the year ended September 30, 2003 was as follows (in thousands):

	Beginning Balance	Increases	Decreases	Ending Balance
Capital assets not depreciated				
Land and improvements	$ 58,690	–	–	58,690
Arts and treasures	405	54	–	459
Total	59,095	54	–	59,149
Property, plant and equipment in service				
Building and improvements	576,259	435	(1,681)	575,013
Equipment	14,430	348	(74)	14,704
Vehicles	3,036	729	(43)	3,722
Completed assets not classified	21,852	–	(56)	21,796
Total	615,577	1,512	(1,854)	615,235
Less accumulated depreciation for				
Building and improvements	(65,658)	(14,792)	1,682	(78,768)
Equipment	(4,713)	(850)	40	(5,523)
Vehicles	(1,685)	(320)	36	(1,969)
Completed assets not classified	(323)	–	–	(323)
Total	(72,379)	(15,962)	1,758	(86,583)
Net property, plant and equipment in service	543,198	(14,450)	(96)	528,652
Construction in progress	7,802	12,639	(1,073)	19,368
Total capital assets	$ 610,095	(1,757)	(1,169)	607,169

7 – CAPITAL ASSETS AND INFRASTRUCTURE, continued

Business-type Activities: Nonmajor Enterprise Funds

Capital asset activity for the year ended September 30, 2003 was as follows (in thousands):

	Beginning Balance	Increases	Decreases	Ending Balance
Capital assets not depreciated				
Land and improvements	$ 40,271	524	–	40,795
Arts and treasures	268	–	–	268
Total	40,539	524	–	41,063
Property, plant and equipment in service				
Building and improvements	300,827	46,429	(5,394)	341,862
Equipment	22,205	1,149	(592)	22,762
Vehicles	37,910	3,546	(1,066)	40,390
Completed assets not classified	73,587	–	(42,976)	30,611
Total	434,529	51,124	(50,028)	435,625
Less accumulated depreciation for				
Building and improvements	(72,514)	(7,471)	4,892	(75,093)
Equipment	(15,401)	(1,661)	477	(16,585)
Vehicles	(15,131)	(3,669)	956	(17,844)
Completed assets not classified	(1,261)	–	501	(760)
Total	(104,307)	(12,801)	6,826	(110,282)
Net property, plant and equipment in service	330,222	38,323	(43,202)	325,343
Construction in progress	38,489	19,833	(8,452)	49,870
Total capital assets	$ 409,250	58,680	(51,654)	416,276

7 – CAPITAL ASSETS AND INFRASTRUCTURE, continued

Business-type Activities

Capital asset activity for the year ended September 30, 2003 was as follows (in thousands):

	Beginning Balance	Increases (1)	Decreases (1)	Ending Balance
Capital assets not depreciated				
Land and improvements	$ 267,163	3,437	–	270,600
Arts and treasures	673	54	–	727
Total	267,836	3,491	–	271,327
Property, plant and equipment in service				
Building and improvements	2,799,995	93,919	(1,031,372)	1,862,542
Equipment	2,696,969	1,178,952	(27,394)	3,848,527
Vehicles	81,516	6,094	(3,191)	84,419
Completed assets not classified	564,978	24,021	(260,562)	328,437
Total	6,143,458	1,302,986	(1,322,519)	6,123,925
Less accumulated depreciation for				
Building and improvements	(816,461)	(46,859)	355,323	(507,997)
Equipment	(1,126,077)	(461,723)	9,032	(1,578,768)
Vehicles	(45,230)	(6,177)	3,064	(48,343)
Completed assets not classified	(9,456)	–	840	(8,616)
Total	(1,997,224)	(514,759)(2)	368,259	(2,143,724)
Net property, plant and equipment in service	4,146,234	788,227	(954,260)	3,980,201
Construction in progress	310,876	526,584	(176,303)	661,157
Nuclear fuel, net of amortization	18,102	3,703	–	21,805
Plant held for future use	31,379	–	–	31,379
Total capital assets	$ 4,774,427	1,322,005	(1,130,563)	4,965,869

(1) Increases and decreases do not include transfers between business-type activities.

(2) Depreciation expense was charged to functions as follows (in thousands):

Business-type activities:	
Electric	$ 89,757
Water and Wastewater	47,980
Airport	15,962
Nonmajor enterprise funds	12,801
Total business-type activities depreciation expense	166,500
Reclassification	348,259
Total increases in accumulated depreciation	$ 514,759

8 – RETIREMENT PLANS

a – Description

The City participates in funding three contributory, defined benefit retirement plans: City of Austin Employees' Retirement and Pension Fund, City of Austin Police Officers' Retirement and Pension Fund, and Fire Fighters' Relief and Retirement Fund of Austin, Texas. An independent board of trustees administers each plan. These plans are City-wide single employer funded plans that cover substantially all full-time employees. The fiscal year of each pension fund ends December 31. The most recently available financial statements of the pension funds are for the year ended December 31, 2002. Membership in the plans at December 31, 2002 is as follows:

	City Employees	Police Officers	Fire Fighters	Total
Retirees and beneficiaries currently receiving benefits and terminated employees entitled to benefits but not yet receiving them	3,387	312	380	4,079
Current employees	7,647	1,364	938	9,949
Total	11,034	1,676	1,318	14,028

Each plan provides service retirement, death, disability and withdrawal benefits. State law governs benefit and contribution provisions. Amendments may be made by the Legislature of the State of Texas.

Financial reports that include financial statements and supplementary information for each plan are publicly available at the locations shown below.

Plan	Address	Telephone
Employees' Retirement and Pension Fund	418 E. Highland Mall Blvd. Austin, Texas 78752	(512)458-2551
Police Officers' Retirement and Pension Fund	P.O. Box 41089 Austin, Texas 78704	(512)416-7138
Fire Fighters' Relief and Retirement Fund	3301 Northland Drive, Suite 215 Austin, Texas 78731	(512)454-9567

8 – RETIREMENT PLANS, continued

b – Funding Policy

	City of Austin Employees' Retirement and Pension Fund	City of Austin Police Officers' Retirement and Pension Fund	Fire Fighters' Relief and Retirement Fund
Authority establishing contributions obligation	State Legislation	State Legislation	State Legislation
Frequency of contribution	Biweekly	Biweekly	Biweekly
Employee's contribution (percent of earnings)	8.0%	9.0%	13.70%
City's contribution (percent of earnings)	8.0% (1)	18.0%	18.05%

(1) The City contributes two-thirds of the cost of prior service benefit payments.

While the contribution requirements are not actuarially determined, state law requires that a qualified actuary approve each plan of benefits adopted. The actuary of each plan has certified that the contribution commitment by the participants and the City provides an adequate financing arrangement. Contributions for fiscal year ended September 30, 2003, are as follows (in thousands):

	City Employees	Police Officers	Fire Fighters	Total
City	$ 26,093	13,626	9,608	49,327
Employees	26,020	6,813	7,605	40,438
Total contributions	$ 52,113	20,439	17,213	89,765

c– Annual Pension Cost and Net Pension Obligation

The City's annual pension cost of $49,327,000 for fiscal year ended September 30, 2003, was equal to the City's required and actual contributions. Three-year trend information is as follows (in thousands):

	City Employees	Police Officers	Fire Fighters	Total
City's Annual Pension Cost (APC):				
2001	$ 24,118	8,429	10,738	43,285
2002	25,986	12,160	9,089	47,235
2003	26,093	13,626	9,608	49,327
Percentage of APC contributed:				
2001	100%	100%	100%	N/A
2002	100%	100%	100%	N/A
2003	100%	100%	100%	N/A
Net Pension Obligation:				
2001	$ –	–	–	–
2002	–	–	–	–
2003	–	–	–	–

8 – RETIREMENT PLANS, continued

Actuarial valuations of the plans are performed every two years. Actuarial updates are done in each year following the full valuation. The latest actuarial valuations were completed as of December 31, 2002. The actuarial cost method and significant assumptions underlying the actuarial calculations are as follows:

	City Employees	Police Officers	Fire Fighters
Actuarial Cost Method	Entry Age Actuarial Cost Method	Entry Age Actuarial Cost Method	Entry Age Actuarial Cost Method
Asset Valuation Basis	5-year smoothed market	5-year smoothed market	5-year smoothed market
Inflation Rate	4%	4%	5%
Projected Annual Salary Increases	4.5% to 14.5%	6.8% average	6.5%
Post retirement benefit increase	None	None	3.5% effective January 1, 2003 through January 1, 2004 and 1% annually thereafter
Assumed Rate of Return on Investments	8%	8%	8%
Amortization method	Level percent of projected pay, open	Level percent of projected pay, open	Level percent of projected pay, open
Remaining Amortization Period	17 years	25.7 years	26.5 years

d – Trend Information (Unaudited)

Information pertaining to the latest actuarial valuations for each Plan is as follows (in thousands):

Valuation Date, December 31st(1)	Actuarial Value of Assets	Actuarial Accrued Liability	UAAL(2)	Funded Ratio	Annual Covered Payroll	Percentage of UAAL to Covered Payroll
City Employees						
1995	$ 707,300	623,000	(84,300)	113.5%	221,000	(38.1%)
1997	856,423	832,140	(24,283)	102.9%	219,208	(11.1%)
1999	1,105,100	1,044,500	(60,600)	105.8%	244,500	(24.8%)
2001	1,311,288	1,360,270	48,982	96.4%	316,793	15.5%
2002	1,250,851	1,440,199	189,348	86.9%	322,008	58.8%
Police Officers						
1995	$ 127,572	164,865	37,293	77.4%	36,211	103.0%
1997	168,602	222,703	54,101	75.7%	47,189	114.6%
1999	226,913	257,850	30,937	88.0%	54,695	56.6%
2001	284,761	347,548	62,787	81.9%	69,707	90.1%
2002	298,782	384,992	86,210	77.6%	79,236	108.8%
Fire Fighters						
1995	$ 213,403	236,994	23,591	90.0%	32,496	72.6%
1997	268,241	279,472	11,231	96.0%	35,130	32.0%
1999	341,593	317,223	(24,370)	107.7%	38,690	(63.0%)
2001	395,371	406,266	10,895	97.3%	49,726	21.9%

(1) City Employees and Police Officers' actuarial valuation are prepared annually beginning in 2002; Fire Fighters' actuarial valuation is prepared bi-annually.
(2) UAAL – Unfunded Actuarial Accrued Liability (Excess)

9 – SELECTED REVENUES

a – Governmental Funds - General Fund

Hospital lease payments
Effective October 1, 1995, the City entered into a long-term lease arrangement with the Daughters of Charity Health Services of Austin ("Seton") to operate City-owned Brackenridge Hospital. This lease agreement qualifies as an operating lease for accounting purposes. Previously, lease payments have been reported in the Hospital Fund, a nonmajor enterprise fund. Beginning in fiscal year 2003, lease payments are reported in the City's General Fund.

The lease agreement specifies a minimum lease payment in addition to a supplemental rent payment based on approximately 46% of net disproportionate share revenue proceeds. In fiscal year 2003, General Fund revenues included minimum lease payments of $1.8 million and additional rent of $6.6 million.

During fiscal year 2003, the City amended the lease agreement to accommodate capacity issues related to the Children's Hospital at Brackenridge. The amendment increases the term of the lease from 30 years to 60 years, with an option to extend an additional 30 years.

Certain adjustments to the scheduled lease payments have resulted from costs associated with the construction of the Austin Women's Hospital, a separately licensed hospital to be operated by the University of Texas Medical Branch at Galveston. Construction costs of approximately $9.3 million will be amortized over the remaining time period of the original lease term (30 years) from the time the facility is completed. The estimated completion date is February 2004; the estimated opening date is the beginning of March 2004.

b – Major Enterprise Funds

Electric and Water and Wastewater
The Texas Public Utility Commission has jurisdiction over electric utility wholesale transmission rates. The City Council has jurisdiction over all other electric utility rates and over all water and wastewater utility rates and other services. The Council determines electric utility and water and wastewater utility rates based on the cost of operations and a debt service coverage approach.

Under a bill passed by the Texas Legislature in 1999, municipally-owned electric utilities such as the City's utility system have the option of offering retail competition after January 1, 2002. At September 30, City management had decided not to enter the retail market, as allowed by State law. Because the effects of entering retail competition are uncertain, a change in accounting policy is not warranted at this time.

Electric rates include a fixed rate and a fuel recovery cost-adjustment factor that allows recovery of coal, gas, purchased power, and other fuel costs. If actual fuel costs differ from amounts billed to customers, deferred or unbilled revenues are recorded by the Electric utility. Any over- or under-collections are applied to the cost-adjustment factor. The fuel factor is revised annually on a calendar year basis or when over- or under-recovery is more than 10% of expected fuel costs.

Airport
The City has entered into certain lease agreements as lessor for concessions at the Airport. These lease agreements qualify as operating leases for accounting purposes. In fiscal year 2003, the Airport Fund revenues included minimum concession guarantees of $8,173,267.

9 – SELECTED REVENUES, continued

The following is a schedule by year of minimum future rentals on noncancelable operating leases for the remaining term of fifty-two years related to the Hospital lease and up to a term of thirty years for the Airport Fund as of September 30, 2003. Amounts for the Hospital lease payments do not include supplemental rent payments as discussed above (in thousands):

Fiscal Year Ended September 30	Governmental General Fund Hospital Lease Payments	Enterprise Airport Lease Payments
2004	$ 1,392	8,246
2005	1,097	7,731
2006	1,097	7,324
2007	1,097	7,156
2008	1,097	6,862
2009-2013	5,483	5,349
2014-2018	5,483	792
2019-2023	5,483	552
2024-2028	2,223	392
2029-2033	50	143
2034-2038	50	–
2039-2043	50	–
2044-2048	50	–
2049-2053	50	–
2054-2055	20	–
Totals	$ 24,722	44,547

10 – DEBT AND NON-DEBT LIABILITIES

a – Short-Term Debt

The following is a summary of changes in short-term debt. Short-term debt provides financing to governmental activities. This debt was issued for interim financing of General Fund operations. Balances at September 30, 2003 are (in thousands):

Description	September 30, 2002	Increases	Decreases	September 30, 2003	Amounts Due Within One Year
Governmental activities					
Tax anticipation notes	$ 4,800	–	(4,800)	–	–

In May 2002, the City issued Tax Anticipation Notes, Series 2002, in the amount of $4,800,000. On April 1, 2003, the City paid the note amount and $73,387 in interest at a rate of 1.6%.

10 – DEBT AND NON-DEBT LIABILITIES, continued

b – Long-Term Liabilities

The following is a summary of long-term liabilities. Balances at September 30, 2003 are (in thousands):

Description	Governmental Activities	Business-Type Activities	Total
Long-term obligations			
General obligation bonds	$ 708,200	23,019	731,219
Certificates of obligation	95,328	34,701	130,029
Contractual obligations	26,230	9,640	35,870
Other tax supported debt	–	11,527	11,527
General obligation bonds and other tax supported debt total	829,758	78,887	908,645
Commercial paper	–	128,484	128,484
Revenue notes	–	28,000	28,000
Revenue bonds	–	3,201,903	3,201,903
Contract revenue bonds	–	16,177	16,177
Capital lease obligations	793	15,165	15,958
Debt service requirements total	830,551	3,468,616	4,299,167
Other long-term obligations			
Accrued compensated absences	69,243	20,919	90,162
Claims payable	34,748	–	34,748
Accrued landfill closure and postclosure costs	–	7,370	7,370
Decommissioning expense payable	–	90,687	90,687
Deferred credits and other liabilities	75,923	507,295	583,218
	179,914	626,271	806,185
Total long-term obligations	$ 1,010,465	4,094,887	5,105,352

This schedule excludes short-term liabilities of $42,459 for governmental activities and $198,271 for business-type activities and long-term interest payable of $150,972 for business-type activities.

Payments on bonds payable for governmental activities will be made in the General Obligation Debt Service Funds. Accrued compensated absences that pertain to governmental activities will be liquidated by the General Fund and Special Revenue Funds. Claims payable will be liquidated by Internal Service Funds. Deferred credits and other liabilities that pertain to governmental activities will be liquidated by the General Fund, Special Revenue Funds, and General Government Capital Improvement Projects Funds.

Internal Service Funds predominately serve the governmental funds. Accordingly, long-term liabilities for these funds are included in governmental activities.

10 – DEBT AND NON-DEBT LIABILITIES, continued

The following is a summary of changes in long-term obligations. Certain long-term obligations provide financing to both governmental and business-type activities. Balances at September 30, 2003 are (in thousands):

Description	September 30, 2002	Increases	Decreases	September 30, 2003	Amounts Due Within One Year
Governmental activities (1)					
General obligation bonds, net	$ 671,300	133,184	(96,284)	708,200	39,321
Certificates of obligation	99,309	650	(4,631)	95,328	4,907
Contractual obligations	24,593	7,380	(5,743)	26,230	6,210
General obligation bonds and other tax supported debt total	795,202	141,214	(106,658)	829,758	50,438
Capital lease obligations	–	1,186	(393)	793	533
Debt service requirements total	795,202	142,400	(107,051)	830,551	50,971
Other long-term obligations					
Accrued compensated absences	64,200	23,686	(18,643)	69,243	28,125
Claims payable	33,381	21,501	(20,134)	34,748	20,121
Deferred credits and other liabilities	70,373	17,187	(11,637)	75,923	56,485
Governmental activities total	963,156	204,774	(157,465)	1,010,465	155,702
Business-type activities:					
Electric activities					
General obligation bonds	1,331	–	(5)	1,326	5
Contractual obligations	1,399	960	(358)	2,001	440
General obligation bonds and other tax supported debt total	2,730	960	(363)	3,327	445
Commercial paper notes, net	200,509	41,416	(187,253)	54,672	–
Revenue bonds, net	1,278,388	189,022	(56,445)	1,410,965	93,374
Capital lease obligations	10,037	1,044	(1,974)	9,107	2,035
Debt service requirements total	1,491,664	232,442	(246,035)	1,478,071	95,854
Other long-term obligations					
Accrued compensated absences	9,936	447	(617)	9,766	5,719
Decommissioning expense payable	81,727	8,960	–	90,687	–
Deferred credits and other liabilities	90,519	53,243	(57,149)	86,613	16,976
Electric activities total	1,673,846	295,092	(303,801)	1,665,137	118,549
Water and Wastewater activities					
General obligation bonds, net	9,418	1,780	(3,694)	7,504	1,493
Contractual obligations	6,901	270	(1,532)	5,639	1,632
Other tax supported debt	12,761	–	(1,234)	11,527	1,136
General obligation bonds and other tax supported debt total	29,080	2,050	(6,460)	24,670	4,261
Commercial paper notes, net	157,842	40,170	(124,200)	73,812	–
Revenue bonds, net	1,088,476	125,299	(14,145)	1,199,630	28,337
Contract revenue bonds, net	22,755	4,446	(11,024)	16,177	2,455
Capital lease obligations	6,600	171	(975)	5,796	1,036
Debt service requirements total	1,304,753	172,136	(156,804)	1,320,085	36,089
Other long-term obligations					
Accrued compensated absences	4,965	102	(204)	4,863	3,041
Deferred credits and other liabilities	391,102	22,016	(2,229)	410,889	3,751
Water and Wastewater activities total	1,700,820	194,254	(159,237)	1,735,837	42,881

(1) Internal Service Funds predominately serve the governmental funds. Accordingly, long-term liabilities for these funds are included in governmental activities.

10 – DEBT AND NON-DEBT LIABILITIES, continued

Description	September 30, 2002	Increases	Decreases	September 30, 2003	Amounts Due Within One Year
Business-type activities (continued):					
Airport activities					
General obligation bonds, net	614	–	(85)	529	53
Contractual obligations	246	–	(63)	183	68
General obligation bonds and other tax supported debt total	860	–	(148)	712	121
Revenue notes	28,000	–	–	28,000	–
Revenue bonds, net	362,340	–	(5,078)	357,262	7,195
Capital lease obligations	–	40	(18)	22	11
Debt service requirements total	391,200	40	(5,244)	385,996	7,327
Other long-term obligations					
Accrued compensated absences	1,246	116	–	1,362	894
Deferred credits and other liabilities	5,099	2,746	(709)	7,136	1,888
Airport activities total	397,545	2,902	(5,953)	394,494	10,109
Nonmajor activities					
General obligation bonds, net	10,291	4,349	(980)	13,660	1,195
Certificates of obligation, net	36,856	3,800	(5,955)	34,701	1,569
Contractual obligations	2,590	–	(773)	1,817	806
General obligation bonds and other tax supported debt total	49,737	8,149	(7,708)	50,178	3,570
Revenue bonds, net	236,698	–	(2,652)	234,046	5,210
Capital lease obligations	–	403	(163)	240	133
Debt service requirements total	286,435	8,552	(10,523)	284,464	8,913
Other long-term obligations					
Accrued compensated absences	5,032	582	(686)	4,928	3,461
Accrued landfill closure and postclosure costs	7,188	182	–	7,370	–
Deferred credits and other liabilities	2,019	4,796	(4,158)	2,657	2,657
Nonmajor activities total	300,674	14,112	(15,367)	299,419	15,031
Total business-type activities					
General obligation bonds, net	21,654	6,129	(4,764)	23,019	2,746
Certificates of obligation, net	36,856	3,800	(5,955)	34,701	1,569
Contractual obligations, net	11,136	1,230	(2,726)	9,640	2,946
Other tax supported debt	12,761	–	(1,234)	11,527	1,136
General obligation bonds and other tax supported debt total	82,407	11,159	(14,679)	78,887	8,397
Commercial paper notes, net	358,351	81,586	(311,453)	128,484	–
Revenue notes	28,000	–	–	28,000	–
Revenue bonds, net	2,965,902	314,321	(78,320)	3,201,903	134,116
Contract revenue bonds	22,755	4,446	(11,024)	16,177	2,455
Capital lease obligations	16,637	1,658	(3,130)	15,165	3,215
Debt service requirements total	3,474,052	413,170	(418,606)	3,468,616	148,183
Other long-term obligations					
Accrued compensated absences	21,179	1,247	(1,507)	20,919	13,115
Accrued landfill closure and postclosure costs	7,188	182	–	7,370	–
Decommissioning expense payable	81,727	8,960	–	90,687	–
Deferred credits and other liabilities	488,739	82,801	(64,245)	507,295	25,272
Business-type activities total	4,072,885	506,360	(484,358)	4,094,887	186,570
Total long-term liabilities	$ 5,036,041	711,134	(641,823)	5,105,352	342,272

There are a number of limitations and restrictions contained in the various bond indentures. The City is in compliance with all limitations and restrictions.

10 – DEBT AND NON-DEBT LIABILITIES, continued

c – Governmental Activities Long-Term Liabilities

General Obligation Bonds - General obligation debt is collateralized by the full faith and credit of the City. The City intends to retire its general obligation debt, plus interest, from future ad valorem tax levies, and is required by ordinance to create from such tax revenues a sinking fund sufficient to pay the current interest due thereon and each installment of principal as it becomes due. General obligation debt issued to finance capital assets of enterprise funds is reported as an obligation of these enterprise funds, although the funds are not obligated by the applicable bond indentures to repay any portion of principal and interest on outstanding general obligation debt. However, the City intends for the enterprise funds to meet the debt service requirements.

The following table summarizes significant facts about general obligation bonds, certificates of obligation, contractual obligations, and assumed municipal utility district (MUD) bonds outstanding at September 30, 2003, including those reported in certain proprietary funds (in thousands):

	Date Issued	Original Issue	Amount Outstanding at September 30, 2003	Aggregate Interest Requirements at September 30, 2003	Interest Rates of Debt Outstanding at September 30, 2003	Maturity Dates of Serial Debt
Series 1993	February, 1993	$ 71,600	$ 52,325	$8,988 (1)	5.50 - 5.75%	9/1/2004-2009
Series 1994	October, 1994	33,260	1,500	78 (1)	5.20%	9/1/2004
Series 1994	October, 1994	3,550	170	9 (1)	5.30%	9/1/2004
Series 1995	October, 1995	30,250	1,985	283 (1)	7.30 - 7.75%	9/1/2004-2005
Series 1995	October, 1995	8,660	820	64 (1)	4.75 - 6.00%	9/1/2004-2005
Series 1996	October, 1996	30,550	8,260	2,284 (1)	4.90 - 6.00%	9/1/2004-2011
Series 1996	October, 1996	11,755	980	24 (2)	4.80%	11/1/2003
Series 1997	October, 1997	29,295	28,315	14,251 (1)	5.00 - 5.75%	9/1/2004-2017
Series 1997	October, 1997	13,975	3,405	155 (2)	4.50%	11/1/2003-2004
Series 1997	October, 1997	2,120	1,695	722 (1)	4.50 - 5.25%	9/1/2004-2017
Series 1998	January, 1998	110,300	109,405	39,490 (1)	4.60 - 5.25%	9/1/2004-2016
Assumed MUD Debt	December, 1997	33,680	13,637	7,746 (3)	4.40 - 10.50%	11/15/2003-2021
Series 1998	October, 1998	13,430	13,130	6,517 (1)	4.40 - 7.13%	9/1/2004-2018
Series 1998	October, 1998	22,770	19,285	8,191 (1)	4.10 - 6.40%	9/1/2004-2018
Series 1998	October, 1998	14,975	6,825	425 (2)	3.90 - 4.00%	11/1/2003-2005
Series 1999	October, 1999	51,100	50,490	32,218 (1)	4.30- 5.75%	9/1/2004-2019
Series 1999	October, 1999	10,335	5,640	549 (2)	4.50 - 4.75%	11/1/2003-2006
Series 1999	October, 1999	5,590	4,870	2,528 (1)	5.00 - 6.00%	9/1/2004-2019
Series 2000	October, 2000	52,930	51,145	34,945 (1)	4.40 - 6.00%	9/1/2004-2020
Series 2000	October, 2000	6,060	5,520	3,022 (1)	5.00 - 5.38%	9/1/2004-2020
Series 2001	June, 2001	123,445	78,345	20,184 (1)	4.75 - 5.50%	9/1/2004-2022
Series 2001	October, 2001	79,650	79,650	45,035 (1)	4.00 - 5.25%	9/1/2004-2021
Series 2001	October, 2001	2,650	2,180	246 (2)	3.00 - 3.88%	11/1/2003-2008
Series 2001	October, 2001	65,335	60,100	24,966 (1)	4.00 - 5.25%	9/1/2004-2021
Series 2002	July, 2002	12,190	12,190	5,024 (1)	3.00 - 5.00%	9/1/2004-2017
Series 2002	July, 2002	2,495	2,495	359 (1)	4.00 - 5.00%	9/1/2004-2009
Series 2002	September, 2002	99,615	99,100	52,173 (1)	2.50 - 5.00%	9/1/2004-2022
Series 2002	September, 2002	8,690	8,230	927 (2)	2.50 - 4.00%	5/1/2004-2009
Series 2002	September, 2002	34,095	33,050	17,209 (1)	2.50 - 5.38%	9/1/2004-2022
Series 2003	June, 2003	62,585	62,585	13,613 (1)	2.25 - 5.00%	9/1/2004-2023
Series 2003	September, 2003	68,855	68,855	40,630 (1)	2.00 - 5.00%	9/1/2004-2023
Series 2003A	September, 2003	2,530	2,530	735 (1)	4.00 - 5.00%	9/1/2004-2013
Series 2003	September, 2003	4,450	4,450	2,375 (1)	4.00 - 4.80%	9/1/2004-2023
Series 2003	September, 2003	8,610	8,610	978 (2)	2.00 - 3.38%	5/1/2004-2010
			$ 901,772			

(1) Interest is paid semiannually on March 1 and September 1.
(2) Interest is paid semiannually on May 1 and November 1.
(3) Interest is paid four times a year on March 1, May 15, September 1, and November 15.

10 – DEBT AND NON-DEBT LIABILITIES, continued

In June 2003, the City issued Public Improvement Refunding Bonds, Series 2003, in the amount of $62,585,000. The net proceeds of $68,864,741 (after issue costs, discounts and premiums) from the refunding were used to refund $66,845,000 of Public Improvement Bonds, Series 1993, 1993A, 1994, 1996 and Certificates of Obligation, Series 1993. The refunding resulted in future interest requirements to service the debt of $14,458,500 with an average interest rate of 4.43%. An economic gain of $5,413,395 was recognized on this transaction. The change in net cash flows that resulted from the refunding was a decrease of $5,650,576. An accounting loss of $1,089,045, which will be deferred and amortized, was recognized on this refunding. The refunded bonds are considered to be legally defeased and the liability for the refunded bonds has been removed from the long-term liabilities.

In September 2003, the City issued Public Improvement and Refunding Bonds, Series 2003, in the amount of $68,855,000. The proceeds from the issue will be used as follows: street improvements ($20,915,000); right of way acquisition and utility relocation ($15,000,000); park and recreation facilities ($14,473,000); emergency centers ($2,940,000); central sub-station and forensics center ($5,565,000); land acquisition ($3,400,000) and refunded a court settlement ($6,562,000). These bonds will be amortized serially on September 1 of each year from 2004 to 2023. Certain of these bonds are callable beginning September 1, 2021. Interest is payable on March 1 and September 1 of each year, commencing March 1, 2004. Total interest requirements for these bonds, at rates ranging from 2% to 5%, are $40,630,445.

In September 2003, the City issued Public Improvement Refunding Bonds, Taxable Series 2003A, in the amount of $2,530,000. Proceeds from the issue will be used to finance certain payment obligations relating to the City's liability under a settlement agreement. These bonds will be amortized serially on September 1 of each year from 2004 to 2013. These bonds are not subject to optional redemption prior to maturity. Interest is payable on March 1 and September 1 of each year, commencing March 1, 2004. Total interest requirements for these bonds, at rates ranging from 4% to 5%, are $735,005.

In September 2003, the City issued Certificates of Obligation, Series 2003, in the amount of $4,450,000. The proceeds from the issue will be used as follows: Walnut Creek–Crystal Brook ($3,800,000) and developer reimbursements ($650,000). These certificates of obligation will be amortized serially September 1 of each year from 2004 to 2023. Certain of these obligations are callable beginning September 1, 2013. Interest is payable on March 1 and September 1 of each year, commencing March 1, 2004. Total interest requirements for these obligations, at rates ranging from 4% to 4.80%, are $2,375,156.

In September 2003, the City issued Public Property Finance Contractual Obligations, Series 2003, in the amount of $8,610,000. The proceeds from the issue will be used as follows: transmission equipment ($530,000); distribution equipment ($430,000); communication technology upgrades ($3,685,000); City Hall technology ($1,785,000); Emergency Medical Services capital equipment ($765,000); fire capital equipment ($1,145,000); and capital equipment vehicles ($270,000). These contractual obligations will be amortized serially May 1 of each year from 2004 to November 1, 2010. Interest is payable on May 1 and November 1 of each year, commencing May 1, 2004. The contractual obligations are not subject to optional redemption prior to maturity. The total interest requirements for these obligations, at rates ranging from 2% to 3.38%, are $977,664.

General obligation bonds authorized and unissued amount to $188,187,000 at September 30, 2003. Bond ratings at September 30, 2003, were Aa2 (Moody's Investor Services, Inc.), AA+ (Standard & Poor's) and AA+ (Fitch).

d – Business-Type Activities Long-Term Liabilities

Utility Debt – The City has previously issued combined debt for the Electric and Water and Wastewater utilities. The City began issuing separate debt for electric and water and wastewater activities in 2000. The following paragraphs describe both combined and separate debt.

10 – DEBT AND NON-DEBT LIABILITIES, continued

Combined Utility Systems Debt – General - The City's Electric Fund and Water and Wastewater Fund comprise the Combined Utility Systems, which issued Combined Utility Systems revenue bonds to finance Electric Fund and Water and Wastewater Fund capital projects. Principal and interest on these bonds are payable solely from the combined net revenues of the Electric Fund and Water and Wastewater Fund.

The total Combined Utility Systems revenue bond obligations at September 30, 2003, exclusive of discounts and premiums, consist of $1,272,069,611 prior lien bonds and $256,379,512 subordinate lien bonds. Aggregate interest requirements for all prior lien and subordinate lien bonds are $1,075,087,026 at September 30, 2003. Revenue bonds authorized and unissued amount to $1,492,642,660 at that date. Bond ratings at September 30, 2003 for the prior lien and subordinate lien bonds were, respectively, A2 and A2 (Moody's Investor Services, Inc.), A and A- (Standard & Poor's), and A+ and A+ (Fitch).

Combined Utility Systems Debt – Revenue Bond Refunding Issues - The Combined Utility Systems have refunded various issues of revenue bonds, notes, and certificates of obligation through refunding revenue bonds. Principal and interest on these refunding bonds are payable solely from the combined net revenues of the City's Electric Fund and Water and Wastewater Fund. The prior lien bonds are subordinate only to the prior lien revenue bonds outstanding at the time of issuance, while the subordinate lien bonds are subordinate to prior lien revenue bonds and to subordinate lien revenue bonds outstanding at the time of issuance.

Some of these bonds are callable prior to maturity at the option of the City. The term bonds are subject to a mandatory redemption prior to the maturity dates as defined in the respective official statements.

The net proceeds of each of the refunding bond issuances were used to purchase U.S. government securities. Those securities were deposited in an irrevocable trust with an escrow agent to provide for all future debt service. As a result, the refunded bonds are considered to be legally defeased and the liability for the refunded bonds has been removed from the financial statements. The accounting gains and losses due to the advance refunding of debt have been deferred and are being amortized over the life of the refunding bonds by the straight-line method. However, a gain or loss on refunded bonds is recognized when funds from current operations are used.

Combined Utility Systems Debt – Bonds Issued and Outstanding - The following schedule shows the original and refunding revenue bonds outstanding at September 30, 2003 (in thousands):

Series	Bonds Dated	Original Amount Issued	Outstanding at September 30, 2003
1989	July 1989	$ 65,800	$ 955
1990AB Refunding	February 1990	236,009	6,388
1992 Refunding	March 1992	265,806	30,116
1992A Refunding	May 1992	351,706	130,416
1993 Refunding	February 1993	203,166	162,186
1993A Refunding	June 1993	263,410	137,469
1994	May 1994	3,500	2,500
1994 Refunding	October 1994	142,559	107,159
1995 Refunding	June 1995	151,770	6,170
1996AB Refunding	September 1996	249,235	237,985
1997 Refunding	August 1997	227,215	218,210
1998 Refunding	August 1998	180,000	172,360
1998A Refunding	August 1998	123,020	62,655
1998 Refunding	November 1998	139,965	139,730
1998A Refunding	November 1998	105,350	105,350
1998	November 1998	10,000	8,800
			$ 1,528,449

10 – DEBT AND NON-DEBT LIABILITIES, continued

Combined Utility Systems Debt – Commercial Paper Notes - The City is authorized by ordinance to issue commercial paper notes in an aggregate principal amount not to exceed $350,000,000 outstanding at any one time. Proceeds from the notes are used to provide interim financing for capital project costs for additions, improvements, and extensions to the City's electric system and the City's water and wastewater system and to refinance, renew, or refund maturing notes and other obligations of the systems. Note ratings at September 30, 2003 were P-1 (Moody's Investor Services, Inc.), A-1 (Standard & Poor's), and F1+(Fitch). The notes will be in denominations of $100,000 or more and mature not more than 270 days from the date of issuance. Principal and interest on the notes are payable from the combined net revenues of the City's Electric Fund and Water and Wastewater Fund.

At September 30, 2003, the Electric Fund had outstanding commercial paper notes of $54,672,000 and the Water and Wastewater Fund had $73,812,000, of commercial paper notes outstanding. Interest rates on the notes range from 0.85% to 1%, adjusted daily, and subsequent issues cannot exceed the maximum rate of 15%.

The City intends to refinance maturing commercial paper notes by issuing long-term debt. During the fiscal year, bonds were issued to refinance commercial paper notes of $187,325,000 and $124,200,000 for the Electric Fund and Water and Wastewater Fund respectively.

Combined Utility Systems Debt – Taxable Commercial Paper Notes - The City is authorized by ordinance to issue taxable commercial paper notes, (the "taxable notes"), in an aggregate principal amount not to exceed $50,000,000 outstanding at any one time. Proceeds from the taxable notes are used to provide interim financing for capital project costs for additions, improvements, and extensions to the City's electric system and the City's water and wastewater system and to refinance, renew, or refund maturing notes and other obligations of the systems. Note ratings at September 30, 2003 were P-1 (Moody's Investor Services, Inc.), A-1+ (Standard & Poor's), and F1+(Fitch).

The taxable notes will be in denominations of $100,000 or more and mature not more than 270 days from the date of issuance. Principal and interest on the taxable notes are payable from the combined net revenues of the City's Electric Fund and Water and Wastewater Fund.

At September 30, 2003, the Electric Fund and the Water and Wastewater Fund had no taxable notes outstanding.

Electric Utility System Revenue Debt – General - The City is authorized by ordinance to issue electric utility system revenue obligations. Proceeds from these separate lien obligations are used only to fund electric capital projects or to refund debt issued to fund these capital projects. Principal and interest on these obligations are payable solely from the net revenues of the Electric Fund.

Electric Utility System Revenue Debt – Revenue Bond Refunding Issues - In March 2003, the City issued Electric Utility System Revenue Refunding Bonds, Series 2003, in an aggregate principal amount of $182,100,000. Proceeds from the bond refunding were used to refund $100,315,000 of the City's outstanding Tax-Exempt Commercial Paper and $87,010,000 of the City's outstanding Taxable Commercial Paper for the Electric Utility System. The debt service requirements on the refunding bonds were $338,188,294. No economic gain or loss was recognized on this transaction. An accounting loss of $71,783, which will be deferred and amortized in accordance with Statement of Financial Accounting Standards No. 71, was recognized on the refunding.

Bond ratings at September 30, 2003 were A3 (Moody's Investor Services, Inc.), A- (Standard & Poor's) and A+ (Fitch).

Electric Utility System Revenue Debt – Bonds Issued and Outstanding - The following table summarizes all electric system separate lien original and refunding revenue bonds outstanding at September 30, 2003 (in thousands):

Series	Bonds Dated	Original Amount Issued	Outstanding at September 30, 2003
2001 Refunding	February 2001	$ 126,700	$ 126,700
2002 Refunding	March 2002	74,750	74,750
2002A Refunding	August 2002	172,880	172,880
2003 Refunding	March 2003	182,100	182,100
			$ 556,430

10 – DEBT AND NON-DEBT LIABILITIES, continued

Water and Wastewater System Revenue Debt – General - The City is authorized by ordinance to issue water and wastewater system revenue obligations. Proceeds from these separate lien obligations are used only to fund water and wastewater capital projects or to refund debt issued to fund these capital projects. Principal and interest on these obligations are payable solely from the net revenues of the Water and Wastewater Fund.

Water and Wastewater System Revenue Debt – Revenue Bond Refunding Issues - In March 2003, the City issued Water and Wastewater System Revenue Refunding Bonds, Series 2003, in an aggregate principal amount of $121,500,000. Proceeds from the bond refunding were used to refund $124,200,000 of the City's outstanding Tax-Exempt Commercial Paper for the Water and Wastewater System. The debt service requirements on the refunding bonds are $222,991,142. No economic gain or loss was recognized on this transaction. No accounting gain or loss was recognized on this refunding.

On August 28, 2003, the City issued Water and Wastewater Contract Revenue Refunding Bonds, Series 2003 in an aggregate principal amount of $4,510,000. Proceeds from the bonds and bank investment funds were used to refund $8,670,000 of the City's outstanding Contract Revenue Bonds for North Austin Municipal Utility District, No. 1, Series 1994. The refunding resulted in future interest requirements of $526,687. An economic gain of $408,815 was recognized on this transaction. The change is net cash flows that resulted from the refunding was a decrease of $416,092. A deferred loss of $75,623, which will be deferred and amortized in accordance with Statement of Financial Accounting Standards No. 71, was recognized on the refunding.

Bond ratings at September 30, 2003 were A2 (Moody's Investor Services, Inc.), A- (Standard & Poor's) and A+ (Fitch).

Water and Wastewater System Revenue Debt – Bonds Issued and Outstanding - The following table summarizes all water and wastewater system separate lien original and refunding revenue bonds outstanding at September 30, 2003 (in thousands):

Series	Bonds Dated	Original Amount Issued	Outstanding at September 30, 2003
Maple Run MUD, 1992	May 1992	$ 17,955	$ 10,265
Tanglewood Forest MUD, 1993	December 1993	1,350	295
North Austin MUD #1, 1994	May 1994	16,570	1,170
2000 Refunding	June 2000	100,000	100,000
2001A Refunding	June 2001	152,180	152,180
2001B Refunding	June 2001	73,200	73,200
2001C Refunding	December 2001	95,380	87,380
2002A Refunding	August 2002	139,695	139,695
2003 Refunding	March 2003	121,500	121,500
North Austin MUD #1, 2003 RFD	August 2003	4,510	4,510
			$ 690,195

10 – DEBT AND NON-DEBT LIABILITIES, continued

Airport – Revenue Bonds - The City's Airport Fund issues Airport System revenue bonds to fund Airport Fund capital projects. Principal and interest on these bonds are payable solely from the net revenues of the Airport Fund. The total Airport System obligation for prior lien bonds is $365,360,000, exclusive of discount and loss on refunding, at September 30, 2003. Aggregate interest requirements for all prior lien bonds are $314,225,386 at September 30, 2003. Revenue bonds authorized and unissued amount to $735,795,000 at that date.

The following table summarizes the original and refunding revenue bonds outstanding at September 30, 2003 (in thousands):

Series	Bonds Dated	Original Amount Issued	Outstanding at September 30, 2003
1989	September 1989	$ 30,000	$ 1,000
1995A	August 1995	362,205	335,185
1995B Refunding	August 1995	31,040	29,175
			$ 365,360

Airport Debt – Variable Rate Revenue Notes - The City is authorized to issue Airport System variable rate revenue notes, pursuant to Ordinance No. 950817B, as amended and restated by Ordinance 980205A adopted by the City Council on February 5, 1998. At September 30, 2003, the Airport System had outstanding variable rate revenue notes of $28,000,000. The debt service fund required by the bond ordinance held assets of $366,202, including accrued interest at September 30, 2003 and was restricted within the Airport System. During fiscal year 2003, interest rates on the notes ranged from 1% to 1.90%, adjusted weekly at market rates, and subsequent rate changes cannot exceed the maximum rate of 15%. Principal and interest on the notes are payable from the net revenues of the Airport System.

Nonmajor fund:

Convention Center – Prior and Subordinate Lien Revenue Bonds - The City's Convention Center Fund issues Convention Center revenue bonds and Hotel Occupancy Tax revenue bonds to fund Convention Center Fund capital projects. Principal and interest on these bonds are payable solely from pledged hotel occupancy tax revenues and the special motor vehicle rental tax revenues. The total Convention Center obligation for prior and subordinate lien bonds is $241,595,000, exclusive of discounts, premiums and loss on refunding, at September 30, 2003. Aggregate interest requirements for all prior and subordinate lien bonds are $202,758,899 at September 30, 2003. Revenue bonds authorized and unissued amount to $760,000 at September 30, 2003.

The following schedule shows the original and refunding revenue bonds outstanding at September 30, 2003 (in thousands):

Series	Bonds Dated	Original Amount Issued	Outstanding at September 30, 2003
1993A	December 1993	$ 75,955	$ 63,395
1999 Refunding	June 1999	6,445	3,200
1999A	June 1999	25,000	25,000
1999	September 1999	110,000	110,000
1999	November 1999	40,000	40,000
			$ 241,595

10 – DEBT AND NON-DEBT LIABILITIES, continued

e -- Debt Service Requirements (in thousands)

Fiscal Year Ended	Governmental Activities					
	General Obligation Bonds		Certificates of Obligation		Contractual Obligations	
September 30	Principal	Interest	Principal	Interest	Principal	Interest
2004	$ 39,321	34,754	4,907	4,512	6,210	768
2005	41,470	32,455	5,014	4,308	5,517	599
2006	48,393	30,464	5,155	4,083	4,181	411
2007	45,764	28,080	5,436	3,851	2,903	287
2008	42,836	25,793	5,711	3,576	2,503	212
2009-2013	208,937	98,001	32,765	13,508	4,916	209
2014-2018	176,380	49,000	23,541	6,697	–	–
2019-2023	95,978	11,432	12,799	1,382	–	–
	699,079	309,979	95,328	41,917	26,230	2,486
Less: Unamortized bond discount	(483)	–	–	–	–	–
Unamortized gain(loss) on bond refundings	(1,151)	–	–	–	–	–
Add: Unamortized bond premium	10,755	–	–	–	–	–
Net debt service requirements	708,200	309,979	95,328	41,917	26,230	2,486

Fiscal Year Ended	Capital Lease Obligations		Total Governmental Debt Service Requirements		
September 30	Principal	Interest	Principal	Interest	Total
2004	533	14	50,971	40,048	91,019
2005	260	3	52,261	37,365	89,626
2006	–	–	57,729	34,958	92,687
2007	–	–	54,103	32,218	86,321
2008	–	–	51,050	29,581	80,631
2009-2013	–	–	246,618	111,718	358,336
2014-2018	–	–	199,921	55,697	255,618
2019-2023	–	–	108,777	12,814	121,591
	793	17	821,430	354,399	1,175,829
Less: Unamortized bond discount	–	–	(483)	–	(483)
Unamortized gain(loss) on bond refundings	–	–	(1,151)	–	(1,151)
Add: Unamortized bond premium	–	–	10,755	–	10,755
Net debt service requirements	793	17	$ 830,551	354,399	1,184,950

10 – DEBT AND NON-DEBT LIABILITIES, continued

e – Debt Service Requirements, continued (in thousands)

Electric Business-Type Activities

Fiscal Year Ended	General Obligation Bonds		Contractual Obligations		Commercial Paper Notes (1)	
September 30	Principal	Interest	Principal	Interest	Principal	Interest
2004	$ 5	69	440	58	54,672	61
2005	5	69	485	47	–	–
2006	5	68	358	30	–	–
2007	53	68	202	19	–	–
2008	88	65	140	14	–	–
2009-2013	555	250	376	18	–	–
2014-2018	603	87	–	–	–	–
2019-2023	12	2	–	–	–	–
Net debt service requirements	1,326	678	2,001	186	54,672	61

Fiscal Year Ended	Revenue Bonds		Capital Lease Obligations		Total Electric Debt Service Requirements		
September 30	Principal	Interest	Principal	Interest	Principal	Interest	Total
2004	93,374	80,798	2,035	579	150,526	81,565	232,091
2005	89,956	72,542	1,957	457	92,403	73,115	165,518
2006	82,612	67,692	1,871	331	84,846	68,121	152,967
2007	114,910	62,948	2,003	202	117,168	63,237	180,405
2008	92,971	62,382	29	61	93,228	62,522	155,750
2009-2013	401,513	354,902	170	283	402,614	355,453	758,067
2014-2018	338,521	123,189	218	235	339,342	123,511	462,853
2019-2023	140,664	59,057	280	173	140,956	59,232	200,188
2024-2028	116,679	23,857	359	94	117,038	23,951	140,989
2029-2033	39,900	2,399	185	10	40,085	2,409	42,494
	1,511,100	909,766	9,107	2,425	1,578,206	913,116	2,491,322
Less: Unamortized bond discount	(11,943)	–	–	–	(11,943)	–	(11,943)
Unamortized gain(loss) on bond refundings	(130,122)	–	–	–	(130,122)	–	(130,122)
Add: Unamortized bond premium	41,930	–	–	–	41,930	–	41,930
Net debt service requirements	$ 1,410,965	909,766	9,107	2,425	1,478,071	913,116	2,391,187

(1) The City intends to refinance maturing commercial paper notes by issuing additional commercial paper notes or by issuing long-term debt.

10 – DEBT AND NON-DEBT LIABILITIES, continued

e – Debt Service Requirements, continued (in thousands)

Water and Wastewater Business-Type Activities

Fiscal Year Ended	General Obligation Bonds		Contractual Obligations		Tax Supported Debt	
September 30	Principal	Interest	Principal	Interest	Principal	Interest
2004	$ 1,493	489	1,632	205	1,136	1,432
2005	1,473	413	1,604	141	1,095	1,223
2006	854	340	1,189	76	864	1,189
2007	1,143	296	554	36	642	430
2008	789	237	324	20	594	401
2009-2013	2,891	680	336	12	2,993	1,585
2014-2018	702	128	–	–	4,220	622
2019-2023	128	16	–	–	–	–
	9,473	2,599	5,639	490	11,544	6,882
Less: Unamortized bond discount	(35)	–	–	–	(84)	–
Unamortized gain(loss) on bond refundings	(2,407)	–	–	–	–	–
Add: Unamortized bond premium	473	–	–	–	67	–
Net debt service requirements	7,504	2,599	5,639	490	11,527	6,882

Fiscal Year Ended	Commercial Paper Notes (1)		Revenue Bonds		Municipal Utility District Contract Revenue Bonds	
September 30	Principal	Interest	Principal	Interest	Principal	Interest
2004	73,812	76	28,337	62,938	2,455	758
2005	–	–	44,769	59,767	2,035	670
2006	–	–	52,768	57,240	2,025	573
2007	–	–	62,911	54,651	2,170	466
2008	–	–	60,839	53,905	2,325	345
2009-2013	–	–	235,843	309,028	5,230	291
2014-2018	–	–	307,243	252,810	–	–
2019-2023	–	–	199,959	129,259	–	–
2024-2028	–	–	190,965	43,576	–	–
2029-2033	–	–	64,100	5,947	–	–
	73,812	76	1,247,734	1,029,121	16,240	3,103
Less: Unamortized bond discount	–	–	(15,131)	–	(31)	–
Unamortized gain(loss) on bond refundings	–	–	(58,959)	–	(75)	–
Add: Unamortized bond premium	–	–	25,986	–	43	–
Net debt service requirements	$ 73,812	76	1,199,630	1,029,121	16,177	3,103

(1) The City intends to refinance maturing commercial paper notes by issuing additional commercial paper notes or by issuing long-term debt.

10 – DEBT AND NON-DEBT LIABILITIES, continued

e – Debt Service Requirements, continued (in thousands)

	Water and Wastewater Business-Type Activities				
Fiscal Year Ended	Capital Lease Obligations		Total Water and Wastewater Debt Service Requirements		
September 30	Principal	Interest	Principal	Interest	Total
2004	$ 1,036	415	109,901	66,313	176,214
2005	1,085	335	52,061	62,549	114,610
2006	1,125	248	58,825	59,666	118,491
2007	1,225	155	68,645	56,034	124,679
2008	1,325	54	66,196	54,962	121,158
2009-2013	–	–	247,293	311,596	558,889
2014-2018	–	–	312,165	253,560	565,725
2019-2023	–	–	200,087	129,275	329,362
2024-2028	–	–	190,965	43,576	234,541
2029-2033	–	–	64,100	5,947	70,047
	5,796	1,207	1,370,238	1,043,478	2,413,716
Less: Unamortized bond discount	–	–	(15,281)	–	(15,281)
Unamortized gain(loss) on bond refundings	–	–	(61,441)	–	(61,441)
Add: Unamortized bond premium	–	–	26,569	–	26,569
Net debt service requirements	$ 5,796	1,207	1,320,085	1,043,478	2,363,563

10 – DEBT AND NON-DEBT LIABILITIES, continued

e – Debt Service Requirements, continued (in thousands)

Airport Business-Type Activities

Fiscal Year Ended	General Obligation Bonds		Contractual Obligations		Revenue Notes (1)	
September 30	Principal	Interest	Principal	Interest	Principal	Interest
2004	$ 53	26	68	7	–	308
2005	45	23	63	4	–	308
2006	18	21	40	2	–	308
2007	49	20	12	1	–	308
2008	36	17	–	–	–	308
2009-2013	173	61	–	–	–	1,540
2014-2018	118	18	–	–	28,000	1,386
2019-2023	8	2	–	–	–	–
	500	188	183	14	28,000	4,466
Less: Unamortized bond discount	(1)	–	–	–	–	–
Unamortized gain(loss) on bond refundings	19	–	–	–	–	–
Add: Unamortized bond premium	11	–	–	–	–	–
Net debt service requirements	529	188	183	14	28,000	4,466

Fiscal Year Ended	Revenue Bonds		Capital Lease Obligations		Total Airport Debt Service Requirements		
September 30	Principal	Interest	Principal	Interest	Principal	Interest	Total
2004	7,195	22,092	11	–	7,327	22,433	29,760
2005	7,650	21,653	11	1	7,769	21,989	29,758
2006	8,415	21,143	–	–	8,473	21,474	29,947
2007	9,015	20,628	–	–	9,076	20,957	30,033
2008	9,565	20,111	–	–	9,601	20,436	30,037
2009-2013	57,730	91,109	–	–	57,903	92,710	150,613
2014-2018	81,445	70,030	–	–	109,563	71,434	180,997
2019-2023	108,025	40,264	–	–	108,033	40,266	148,299
2024-2028	76,320	7,195	–	–	76,320	7,195	83,515
	365,360	314,225	22	1	394,065	318,894	712,959
Less: Unamortized bond discount	(6,670)	–	–	–	(6,671)	–	(6,671)
Unamortized gain(loss) on bond refundings	(1,428)	–	–	–	(1,409)	–	(1,409)
Add: Unamortized bond premium	–	–	–	–	11	–	11
Net debt service requirements	$ 357,262	314,225	22	1	385,996	318,894	704,890

(1) These are variable rate notes with 1.10% interest.

10 – DEBT AND NON-DEBT LIABILITIES, continued

e -- Debt Service Requirements, continued (in thousands)

Nonmajor Business-Type Activities

Fiscal Year Ended	General Obligation Bonds		Certificates of Obligation		Contractual Obligations	
September 30	Principal	Interest	Principal	Interest	Principal	Interest
2004	$ 1,195	696	1,569	1,610	806	65
2005	1,649	639	1,616	1,535	530	31
2006	1,636	563	1,355	1,465	207	14
2007	994	480	1,429	1,408	99	8
2008	1,261	433	1,504	1,339	67	5
2009-2013	5,571	1,231	8,810	5,617	108	4
2014-2018	1,652	179	11,469	3,380	–	–
2019-2023	63	7	6,880	794	–	–
	14,021	4,228	34,632	17,148	1,817	127
Less: Unamortized bond discount	(44)	–	–	–	–	–
Unamortized gain(loss) on bond refundings	(997)	–	–	–	–	–
Add: Unamortized bond premium	680	–	69	–	–	–
Net debt service requirements	13,660	4,228	34,701	17,148	1,817	127

Fiscal Year Ended	Revenue Bonds		Capital Lease Obligations		Total Nonmajor Debt Service Requirements		
September 30	Principal	Interest	Principal	Interest	Principal	Interest	Total
2004	5,210	13,251	133	3	8,913	15,625	24,538
2005	6,070	12,961	107	4	9,972	15,170	25,142
2006	6,505	12,631	–	–	9,703	14,673	24,376
2007	6,330	12,300	–	–	8,852	14,196	23,048
2008	6,655	11,973	–	–	9,487	13,750	23,237
2009-2013	38,880	54,097	–	–	53,369	60,949	114,318
2014-2018	50,610	42,016	–	–	63,731	45,575	109,306
2019-2023	47,955	27,539	–	–	54,898	28,340	83,238
2024-2028	49,335	14,564	–	–	49,335	14,564	63,899
2029-2033	24,045	1,427	–	–	24,045	1,427	25,472
	241,595	202,759	240	7	292,305	224,269	516,574
Less: Unamortized bond discount	(2,365)	–	–	–	(2,409)	–	(2,409)
Unamortized gain(loss) on bond refundings	(5,663)	–	–	–	(6,660)	–	(6,660)
Add: Unamortized bond premium	479	–	–	–	1,228	–	1,228
Net debt service requirements	$ 234,046	202,759	240	7	284,464	224,269	508,733

10 – DEBT AND NON-DEBT LIABILITIES, continued

e – Debt Service Requirements, continued (in thousands)

	Business-Type Activities					
Fiscal Year Ended	General Obligation Bonds		Certificates of Obligation		Contractual Obligations	
September 30	Principal	Interest	Principal	Interest	Principal	Interest
2004	$ 2,746	1,280	1,569	1,610	2,946	335
2005	3,172	1,144	1,616	1,535	2,682	223
2006	2,513	992	1,355	1,465	1,794	122
2007	2,239	864	1,429	1,408	867	64
2008	2,174	752	1,504	1,339	531	39
2009-2013	9,190	2,222	8,810	5,617	820	34
2014-2018	3,075	412	11,469	3,380	–	–
2019-2023	211	27	6,880	794	–	–
	25,320	7,693	34,632	17,148	9,640	817
Less: Unamortized bond discount	(80)	–	–	–	–	–
Unamortized gain(loss) on bond refundings	(3,385)	–	–	–	–	–
Add: Unamortized bond premium	1,164	–	69	–	–	–
Net debt service requirements	23,019	7,693	34,701	17,148	9,640	817

Fiscal Year Ended	Tax Supported Debt		Commercial Paper Notes (1)		Revenue Notes (2)	
September 30	Principal	Interest	Principal	Interest	Principal	Interest
2004	1,136	1,432	128,484	137	–	308
2005	1,095	1,223	–	–	–	308
2006	864	1,189	–	–	–	308
2007	642	430	–	–	–	308
2008	594	401	–	–	–	308
2009-2013	2,993	1,585	–	–	–	1,540
2014-2018	4,220	622	–	–	28,000	1,386
	11,544	6,882	128,484	137	28,000	4,466
Less: Unamortized bond discount	(84)	–	–	–	–	–
Add: Unamortized bond premium	67	–	–	–	–	–
Net debt service requirements	11,527	6,882	128,484	137	28,000	4,466

(1) The City intends to refinance maturing commercial paper notes by issuing additional commercial paper notes or by issuing long-term debt.

(2) These are variable rate notes with 1.10% interest.

10 – DEBT AND NON-DEBT LIABILITIES, continued

e – Debt Service Requirements, continued (in thousands)

Fiscal Year Ended September 30	Business-Type Activities					
	Revenue Bonds		Municipal Utility District Contract Revenue Bonds		Capital Lease Obligations	
	Principal	Interest	Principal	Interest	Principal	Interest
2004	$ 134,116	179,079	2,455	758	3,215	997
2005	148,445	166,923	2,035	670	3,160	797
2006	150,300	158,706	2,025	573	2,996	579
2007	193,166	150,527	2,170	466	3,228	357
2008	170,030	148,371	2,325	345	1,354	115
2009-2013	733,966	809,136	5,230	291	170	283
2014-2018	777,819	488,045	–	–	218	235
2019-2023	496,603	256,119	–	–	280	173
2024-2028	433,299	89,192	–	–	359	94
2029-2033	128,045	9,773	–	–	185	10
	3,365,789	2,455,871	16,240	3,103	15,165	3,640
Less: Unamortized bond discount	(36,109)	–	(31)	–	–	–
Unamortized gain(loss) on bond refundings	(196,172)	–	(75)	–	–	–
Add: Unamortized bond premium	68,395	–	43	–	–	–
Net debt service requirements	3,201,903	2,455,871	16,177	3,103	15,165	3,640

Fiscal Year Ended September 30	Total Business-Type Activities Debt Service Requirements		
	Principal	Interest	Total
2004	276,667	185,936	462,603
2005	162,205	172,823	335,028
2006	161,847	163,934	325,781
2007	203,741	154,424	358,165
2008	178,512	151,670	330,182
2009-2013	761,179	820,708	1,581,887
2014-2018	824,801	494,080	1,318,881
2019-2023	503,974	257,113	761,087
2024-2028	433,658	89,286	522,944
2029-2033	128,230	9,783	138,013
	3,634,814	2,499,757	6,134,571
Less: Unamortized bond discount	(36,304)	–	(36,304)
Unamortized gain(loss) on bond refundings	(199,632)	–	(199,632)
Add: Unamortized bond premium	69,738	–	69,738
Net debt service requirements	$3,468,616	2,499,757	5,968,373

11 – CONDUIT DEBT

The City has issued several series of housing and industrial development revenue bonds to provide for low cost housing and for acquisition and construction of industrial and commercial facilities. These bonds are secured by the property financed and are payable solely from payments received on the underlying mortgage loans. Prior to September 30, 1997 the City issued several series of bonds; the aggregate principal amount payable of these bonds could not be determined; however, their original issue amounts totaled $310.2 million. Since 1997, the City has issued various series of bonds, with the original issues totaling $84.4 million; and $84 million is outstanding at September 30, 2003.

The City has issued various facility revenue bonds to provide for facilities located at the airport and convention center. These bonds are special limited obligations, payable solely from and secured by a pledge of revenue to be received from agreements between the City and various third parties. The original issues totaled $367.4 million, with $362.5 million outstanding at September 30, 2003.

The above bonds do not constitute a debt or pledge of the faith and credit of the City and accordingly have not been reported in the accompanying financial statements.

12 – INTERFUND BALANCES AND TRANSFERS

Interfund receivables and payables at September 30, 2003, are as follows (in thousands):

		Amount	
Receivable Fund	**Payable Fund**	**Current**	**Long-Term**
Governmental funds:			
Nonmajor governmental funds	General Fund	$ 6	–
	Nonmajor governmental funds	36,919	–
	Water and Wastewater	–	3,293
	Nonmajor enterprise funds	–	1,176
	Internal service funds	–	208
Business-type funds:			
Electric	Nonmajor enterprise funds	–	2,520
Water and Wastewater (restricted)	Internal service funds	27	188
Airport (restricted)	General Fund	700	2,217
	Nonmajor governmental funds	–	184
Nonmajor enterprise funds	Nonmajor governmental funds	–	64
		$ 37,652	9,850

Interfund receivables and payables reflect temporary loans between funds. Of the above current amount, $14.5 million is an interfund loan from the Fiscal Surety Fund, a special revenue fund, to other special revenue funds (primarily grant funds) to cover deficit pooled investments and cash.

Interfund transfers during fiscal year 2003 were as follows (in thousands):

	Transfers In			
Transfers Out	**General Fund**	**Nonmajor Governmental**	**Nonmajor Enterprise**	**Total**
General Fund	$ –	12,623	8,506	21,129
Nonmajor governmental funds	–	17,519	23,528	41,047
Electric	72,864	1,772	–	74,636
Water and Wastewater	19,553	2,962	–	22,515
Airport	–	48	–	48
Nonmajor enterprise funds	–	1,761	–	1,761
Internal service funds	–	156	–	156
Total transfers out	$ 92,417	36,841	32,034	161,292

12 – INTERFUND BALANCES AND TRANSFERS, continued

Interfund operating transfers are authorized through City Council approval. Significant transfers include the Electric and Water and Wastewater transfers to the General Fund, which are comparable to a return on investment to owners.

13 – LITIGATION

A number of claims against the City are pending with respect to various matters arising in the normal course of the City's operations. Legal counsel and City management are of the opinion that settlement of these claims and pending litigation will not have a material effect on the City's financial statements. The City has accrued liabilities in the Liability Reserve Fund for claims payable at September 30, 2003. These liabilities include amounts for lawsuits settled subsequent to year-end, which are reported in the government-wide statement of net assets.

14 – COMMITMENTS AND CONTINGENCIES

a – Fayette Power Project

Austin Energy's coal-fired electric generating units are located at the Fayette Power Project (FPP) and operate pursuant to a participation agreement with the Lower Colorado River Authority (LCRA, Project Manager). Austin Energy has an undivided 50 percent interest in Units 1 and 2, and LCRA wholly owns Unit 3. Austin Energy's investment is financed with City funds, and its pro-rata share of operations is recorded as if wholly owned. Austin Energy's equity in FPP was $27.8 million as of September 30, 2003. The equity interest in the FPP is calculated pursuant to the participation agreement and is reported in various asset and liability accounts within the City's financial statements.

The original cost of the Austin Energy's share of FPP's generation and transmission facilities is recorded in the utility plant accounts of the City in accordance with its accounting policies. Each participant issued its own debt to finance its portion of construction costs. The City's portion was financed through utility revenue bonds. In addition, each participant has the obligation to finance its portion of any operating and capital costs, as well as its deficits.

A management committee of four members governs the Project; each participant administratively appoints two members. As managing partner, LCRA is responsible for the operation of the Project and appoints Project management.

b – South Texas Project

Austin Energy is one of four participants in the South Texas Project (STP), which consists of two 1,250-megawatt nuclear generating units in Matagorda County, Texas. The other participants in the STP are Reliant Energy, American Electric Power, formerly known as Central Power and Light Company, and City Public Service of San Antonio. In-service dates for STP were August 1988 for Unit 1 and June 1989 for Unit 2. Austin Energy's 16 percent ownership in the STP represents 400 megawatts of plant capacity. At September 30, 2003 Austin Energy's investment in the STP was approximately $620 million, net of accumulated depreciation.

Effective November 17, 1997, the Participation Agreement among the owners of STP was amended and restated and the STP Nuclear Operating Company (STPNOC), a Texas non-profit non-member corporation created by the participants, assumed responsibility as the licensed operator of STP. The participants share costs in proportion to ownership interests, including all liabilities and expenses of STPNOC. Each participant is responsible for its own funding for STP. The City's portion is financed through operations, revenue bonds or commercial paper, which are repaid by the Electric Fund (see Note 10). In addition, each participant has the obligation to finance any deficits that may occur.

Each participant appoints one member to the board of directors of STPNOC, as well as one other member to the owner's committee. A member of the owner's committee may serve on the board of directors in the absence of a board member. The City's portion of STP is classified as plant in service, construction in progress and nuclear fuel inventory. Nuclear fuel includes fuel in the reactor as well as nuclear fuel in process.

14 – COMMITMENTS AND CONTINGENCIES, continued

c – South Texas Project Decommissioning

The South Texas Project (STP) is subject to regulation by the Nuclear Regulatory Commission (NRC). The NRC requires that each holder of a nuclear plant operating license submit information to the NRC indicating the minimum funding required to decommission the plant. In addition, reasonable assurance must be demonstrated that sufficient funds are being accumulated to provide the minimum requirement for decommissioning. This amount must be adjusted annually as required by the NRC. At September 30, 2003, Austin Energy funded its share of the estimated decommissioning liability as follows:

	2003
Estimated cost to decommission STP	$233,140,066
Restricted decommissioning fund assets	90,687,258

Austin Energy and other STP participants have provided the required information to the NRC and have been collecting decommissioning funds through rates since 1989. Austin Energy has established an external irrevocable trust for collecting sufficient funds for its share of the estimated decommissioning costs. For fiscal year 2003, Austin Energy collected $4,958,221 for decommissioning expenses.

d – Energy Risk Management Program

In August 2003, in an effort to mitigate the financial and market risk associated with the purchase of natural gas and energy price volatility, Austin Energy initiated the Energy Risk Management Pilot Program. This program was authorized by the Austin City Council and is led by the Risk Oversight Committee. Under this program, Austin Energy enters into futures contracts, options, and swaps for the purpose of reducing exposure to natural gas and energy price risk. Use of these types of instruments for the purpose of reducing exposure to price risk is performed as a hedging activity. These contracts may be settled in cash or delivery of certain commodities. Austin Energy typically settles these contracts in cash.

Austin Energy has entered into brokerage agreements with the following organizations to execute the exchange traded instruments for Austin Energy's risk management activities:

Brokerage	Credit Rating
Citigroup Global Market Holding Inc.	AA-
Man Group	A3

The hedging related contracts are reported at cost on the statement of net assets. The gains and losses related to these transactions are netted to fuel expense in the period realized. As of September 30, 2003, Austin Energy's options, futures, and basis swaps, valued at mark-to-market, net to an unrealized loss of $271,650. This reflects the difference between the cost and the fair market value of these contracts at September 30, 2003. Initial margins are flat fees per contract and are paid in cash. Fair market values are calculated by multiplying the number of outstanding contracts by the forward prices as quoted by the New York Mercantile Exchange. The unrealized gain/loss refers to the difference between the cost and fair market value of the contracts, which is not included in the financial statements at September 30, 2003.

Futures	
Contracts effective date	August 25 through September 22, 2003
Contracts maturity date	November 1, 2003 through February 1, 2004
Initial margin	$648,000
Cost	$5,268,950
Fair market value	$5,018,000
Unrealized (Gain)/Loss	$250,950

Options	
Contracts effective date	September 12 through September 22, 2003
Contracts maturity date	November 1, 2003 through March 1, 2004
Fair Value	$25,700
Unrealized (Gain)/Loss	$19,700

14 – COMMITMENTS AND CONTINGENCIES, continued

The options and future contracts expose Austin Energy to a minimal amount of credit risk. In the event of default or nonperformance by brokers or the exchange, the operations of Austin Energy will not be materially affected. However, Austin Energy does not expect the brokerages to fail to meet their obligations given their high credit rating and the strict and deep credit requirements upheld by the New York Mercantile Exchange of which these brokerage houses are members. Termination risk for exchange traded instruments is greatly reduced by the strict rules and guidelines set up by the exchange, which are governed by the Commodity Futures Trade Commission.

Swaps	
Contracts effective date	September 22, 2003
Contracts maturity date	November 1, 2003
Cost	$112,000
Fair market value	$113,000
Unrealized (Gain)/Loss	$ 1,000

The swap agreements expose Austin Energy to credit, termination, and non-performance risk. However, Austin Energy does not expect the swap counterparty to fail to meet its obligation given its high credit rating of A by S&P, and A3 by Moody's. Austin Energy's exposure to termination and non-performance risk is minimal due to the high credit rating of the counterparty, and the contractual provisions under the ISDA (International Swaps and Derivatives Association) agreement applied to the swaps.

e – Certificates of Participation

The City has entered into several capital lease arrangements through the issuance of Certificates of Participation as follows:

$23,060,000 Certificates of Participation, City of Austin, Texas Electric Utility Office Project, Series 1987

$14,000,000 Certificates of Participation, City of Austin, Texas Water and Wastewater Utility Office Project, Series 1987

The certificates represent proportionate interests in lease payments to be made by the City to a third-party lessor. The City has title to the office projects, pursuant to general warranty deeds; however, the trustee maintains a vendor's lien and superior title to the properties until all sums due are paid in full.

The City's obligations under the lease agreements are subject to and dependent upon annual appropriations by the City Council and do not obligate the City to levy or pledge any form of taxation. Thus, the certificates are treated as capital lease obligations rather than as long-term bonds and are recorded as a liability in the respective utility's funds.

The following table presents information regarding these certificates:

Description	Electric Fund Office Project (1)	Water and Wastewater Fund Office Project (1)
Date issued	February 1987	August 1987
Amount issued	$23,060,000	$14,000,000
Interest rates	4.00% - 7.00%	5.25% - 8.00%
Interest payable on	March 15 and September 15	May 15 and November 15
Maturity dates	September 15 1988 - 2007	November 15 1989 - 2007
Present value of lease payments	$7,160,000	$5,700,000
Reserve Fund (2)	$ 2,000,000	$1,250,000

(1) Subject to mandatory redemption upon the occurrence of certain events.
(2) Held by trustee, to be used to make final payments.

14 – COMMITMENTS AND CONTINGENCIES, continued

f – Federal and State Financial Assistance Programs

The City participates in a number of federally assisted and State grant programs, financed primarily by the U.S. Housing and Urban Development (HUD) Department, U.S. Health and Human Services (HHS) Department, and U.S. Department of Transportation (DOT). The City's programs are subject to program compliance audits by the granting agencies. Management believes that no material liability will arise from any such audits.

g – Arbitrage Rebate Payable

The City's financial advisor has determined that the City has earned interest revenue on unused bond proceeds in excess of amounts allowed by applicable Federal regulations. The City will be required to rebate funds to the federal government. The estimated amounts payable at September 30, 2003 are as follows (in thousands):

Governmental Activities	Business-type Activities				
	Electric	Water and Wastewater	Airport	Nonmajor	Total
$ 1,688	436	477	2	135	$ 1,050

h – Capital Improvement Plan

As required by the City Charter, the City has a *Five Year Capital Improvement Plan* (Capital Budget) that is an anticipated spending plan for projects in the upcoming and future years. The City's 2004 Capital Budget includes new appropriations of $401.1 million for the City's enterprise funds and $72.2 million for general government projects. The City has substantial contractual commitments relating to its capital improvement plan.

The key projects in progress include parks development and improvements, financial and administrative, transportation improvements, electric system improvements, water and wastewater system improvements and annexations and airport improvements as shown below (in thousands). Remaining commitments represent current unspent budget and future costs required to complete projects.

Project	Spent-to-Date	Remaining Commitment
Governmental activities:		
Parks development and improvements	$ 109,815	29,132
Financial and administrative	135,204	17,871
Transportation improvements	321,543	126,453
Other governmental	219,190	45,667
Business-type activities:		
Electric system improvements	1,068,373	285,924
Water and wastewater system improvements and annexations	1,038,258	1,471,509
Airport improvements	81,919	111,439
Nonmajor enterprise	137,567	28,183
Total	$ 3,111,869	2,116,178

i – Operating lease with Daughters of Charity Health Services of Austin

Effective October 1, 1995, the City entered into a long-term lease arrangement with the Daughters of Charity Health Services of Austin ("Seton"). Under the terms of the lease, Seton will operate City-owned Brackenridge Hospital and will provide all necessary medical services for residents of Austin regardless of their ability to pay. The City will reimburse Seton for services provided through three programs. Under the Charity Care Program, the City will reimburse Seton a maximum of $5.6 million annually for providing medical care to the medically indigent; provided however, that Seton must first provide charity care in the amount of 4% of net revenues as required by State law. Under the Medical Assistance Program (MAP), the City paid Seton approximately $9.8 million in fiscal year 2003 for patients enrolled in this program. Under the Physician Services Program, the City paid Seton approximately $5.6 million during fiscal year 2003 for providing physician services to patients in the first two programs.

14 – COMMITMENTS AND CONTINGENCIES, continued

In May 2003, the City amended the lease agreement to accommodate capacity issues related to the Children's Hospital at Brackenridge. In order to meet future community needs for pediatric medical services, the City Council approved moving the Children's Hospital to the former site of Robert Mueller Airport. The new Children's Hospital will be owned and operated by Seton. Other provisions of the amendment include lengthening the lease term from an original term of 30 years to 60 years (with an optional 30 year extension), increasing the breach of contract penalty from $5 million to $50 million, and adding a requirement that Seton spend a minimum of $50 million for capital at Brackenridge over the next 20 years; of which $30 million must be spent within the next 10 years. The lease amendment also strengthens financial provisions related to the operation of the Austin Women's Hospital. The cost of the leased assets as of September 30, 2003 is as follows (in thousands):

	Cost	Accumulated Depreciation
Land and other nondepreciable assets	$ 803	–
Property, plant and equipment in service	73,990	(37,363)

j – Landfill Closure and Postclosure Liability

State and federal regulations require the City to place a final cover on the City of Austin landfill site (located on FM 812) when it stops accepting waste and to perform certain maintenance and monitoring functions at the site for thirty years after closure. Although closure and postclosure care costs will be paid only near or after the date that the landfill stops accepting waste, the City reports in the Solid Waste Services Fund, a nonmajor enterprise fund, a portion of these closure and postclosure care costs as an operating expense in each period, based on landfill capacity used as of each balance sheet date. The $7.4 million reported as accrued landfill closure and postclosure costs at September 30, 2003, represents the cumulative amount reported to date based on the use of 81.2% of the estimated capacity of the landfill. The Solid Waste Services Fund will recognize the remaining estimated cost of closure and postclosure care of $1.7 million as the remaining estimated capacity is filled over the next nine years. The total estimated costs of $9.1 million include costs of closure in 2012 of $2.4 million and postclosure costs over the subsequent thirty years of $6.7 million. These amounts are based on what it would cost to perform all closure and postclosure care in 2003. Actual costs may be higher due to inflation, changes in technology or changes in regulations. State and federal laws require owners to demonstrate financial assurance for closure, postclosure, and/or corrective action. The City complies with the financial and public notice components of the local government financial test and government-guarantee of the test.

k – Risk-Related Contingencies

The City uses internal service funds to account for risks related to health benefits, third-party liability, and workers' compensation. The funds are as follows:

Fund name	Description
Employee Benefits	City employees and retirees may choose between a self-insured PPO or an HMO. Approximately 23% of City employees and 57% of retirees use the HMO option; approximately 77% of City employees and 43% of retirees use the PPO, which is self-insured. Costs are charged to City funds through a charge per employee per pay period.
Liability Reserve	Self-insured. Includes losses and claims related to liability for bodily injury, property damage, professional liability and certain employment liability. Excludes losses and claims related to health benefits or workers' compensation. Premiums are charged to other City funds each year based on historical costs.
Workers' Compensation	Self-insured. Premiums are charged to other City funds each year based on historical costs.

The City purchases stop loss insurance for the City's PPO. This stop loss insurance covers individual claims that exceed $500,000 per calendar year beginning in calendar year 2002 and $150,000 per calendar year prior to calendar year 2002, up to a maximum of $1 million. During fiscal year 2003, one claim exceeded the stop loss limit of $500,000; no claims exceeded the stop loss limit of $500,000 in fiscal year 2002; and two claims exceeded the stop loss limit of $150,000 in fiscal year 2001. City coverage is limited to $1 million in lifetime benefits. The City does not purchase stop loss insurance for workers' compensation claims.

14 – COMMITMENTS AND CONTINGENCIES, continued

The City is self-insured for much of its risk exposure; however, the City purchases commercial insurance coverage for loss or damage to real property, theft and other criminal acts committed by employees, and third party liability associated with the airport, owned aircraft, and electric utility operations. There have been no claims settlements in excess of the insurance coverage that has been procured. The City also purchases a broad range of insurance coverage through a program that provides workers' compensation, employer's liability and third party liability coverage to contractors working on designated capital improvement project sites.

Liabilities are reported when it is probable that a loss has been incurred at the date of the financial statements and the amount of the loss can be reasonably estimated. Liabilities include an amount for claims that have been incurred but not reported (IBNRs). The City utilizes actuarial information and historical claim settlement trends to determine the claim liabilities for the Employee Benefits Fund and Worker's Compensation Fund; liabilities for the Liability Reserve Fund are calculated based on outstanding claims. The amount to be paid out ultimately may be more or less than the amount accrued at September 30, 2003. The possible range of loss is $34.7 to $45.4 million. The City contributes amounts to an internal service fund based on an estimate of anticipated costs for claims each year.

Changes in the balances of claims liability are as follows (in thousands):

	Employee Benefits		Liability Reserve		Workers' Compensation	
	2003	2002	2003	2002	2003	2002
Liability balances, beginning of year	$ 4,618	4,470	21,899	12,700	6,864	6,347
Claims and changes in estimates	5,328	3,569	9,586	11,065	6,587	4,663
Claim payments	(4,405)	(3,421)	(11,405)	(1,866)	(4,324)	(4,146)
Liability balances, end of year	$ 5,541	4,618	20,080	21,899	9,127	6,864

The Liability Reserve Fund claims liability balance at fiscal year end includes liabilities of $4.9 million discounted at 5.02% in 2003 and $5.3 million discounted at 4.87% in 2002.

In early FY2004, the City reached a settlement agreement in a litigation matter with Christopher Ochoa in the amount of $5.3 million to be paid in FY2004. This amount is included in the financial statements as presented.

l – Environmental Remediation Contingencies

The Electric Fund may incur costs for environmental remediation of certain sites including the Holly and Seaholm Power Plants. The financial statements include a liability of $7.2 million at September 30, 2003. This amount includes the cost of penalties associated with an Environmental Protection Agency (EPA) PCB inspection and estimated remaining costs for the remediation of the contaminated sites. The Electric Fund anticipates payment of these costs in 2004 and future years.

The EPA previously issued an Administrative Order to the Water and Wastewater Utility. The Utility must conduct studies of its wastewater collection system, eliminate overflows by December 2007, and make necessary capital improvements to repair and/or rehabilitate collection system infrastructure. When the studies are complete, the Utility will be able to estimate the cost of the improvements. The Utility currently is complying with all requirements of the Administrative Order.

The Airport Fund may also incur costs for the environmental remediation of certain sites and has recorded an estimated liability of $1.9 million in the financial statements.

m – Other Commitments and Contingencies

The City is committed under various leases for building and office space, tracts of land and rights of way, and various equipment. These leases are considered operating leases for accounting purposes. Lease expense for the year ended September 30, 2003 was $19.8 million. The City expects these leases to be replaced with similar leases in the ordinary course of business. Future minimum lease payments for these leases will remain approximately the same.

14 – COMMITMENTS AND CONTINGENCIES, continued

The City has entered into certain lease agreements, including the certificates of participation, as lessee for financing equipment purchases for Electric and Water and Wastewater Utilities and for financing personal computers for both governmental and business-type departments. These lease agreements qualify as capital leases for accounting purposes and have been recorded at the present value of the future minimum lease payments at their inception date. Refer to Note 10 for the debt service requirements on these leases.

The following summarizes assets recorded at September 30, 2003, under capital lease obligations (in thousands):

		Business-type Activities				
Assets	Governmental Activities	Electric	Water and Wastewater	Airport	Nonmajor	Total
Building and improvements	$ –	21,604	12,750	–	–	$ 34,354
Equipment	890	1,445	240	58	1,808	3,551
Accumulated depreciation	(407)	(9,319)	(4,093)	(25)	(862)	(14,299)
Net assets	$ 483	13,730	8,897	33	946	$ 23,606

15 – OTHER POST-EMPLOYMENT BENEFITS

In addition to making contributions to the three pension systems, the City provided certain other post-employment benefits to its retirees. Other post-employment benefits include access to medical and dental insurance for the retiree and the retiree's family and $1,000 of life insurance on the retiree only.

All retirees who are eligible to receive pension benefits under any of the City's three pension systems are eligible for other post-employment benefits. Retirees may also enroll eligible dependents under the medical and dental plan(s) in which they participate. Eligible dependents of the retiree include a legally married spouse, unmarried children under age 25 who are dependent upon the retiree for support, including natural children, stepchildren, legally adopted children, children for whom the retiree has obtained court-ordered guardianship/conservatorship, qualified children placed pending adoption, and grandchildren who qualify as a dependent on the retiree's or retiree's spouse's federal income tax return, and eligible disabled children beyond 25 years of age if covered prior to age 25. A surviving spouse of a deceased retiree may continue medical coverage until the date the surviving spouse remarries. A surviving spouse of a deceased retiree may continue dental coverage for 36 months by paying the entire premium plus a 2 percent administrative fee. Other surviving dependents of a deceased retiree may continue medical and dental coverage for 36 months by paying the entire premium plus a 2 percent administrative fee.

The City is under no obligation, statutory or otherwise, to offer other post-employment benefits or to pay any portion of the cost of other post-employment benefits to any retirees. Allocation of City funds to pay other post-employment benefits or to make other post-employment benefits available is determined on an annual basis by the City Council as part of the budget process.

The City pays a portion of the retiree's medical insurance premium and a portion of the retiree's dependents' medical insurance premium. The portion paid by the City varies according to age, coverage selection and years of service. The percentage of the medical insurance premium paid by the City ranges as follows:

Years of Service	Retiree only	Dependent only
Less than 5 years	16% - 22%	10% - 31%
5 to 9 years	24% - 29%	15% - 35%
10 to 14 years	40% - 44%	25% - 43%
15 to 20 years	56% - 59%	35% - 54%
Greater than 20 years	80% - 81%	50% - 76%

15 – OTHER POST-EMPLOYMENT BENEFITS, continued

The City pays 100% of the retiree's life insurance premium. Group dental coverage is available to retirees and their eligible dependents. The retiree pays the full cost of the dental premium.

Other post-employment benefits are expensed and funded on a pay-as-you-go basis. The City recognizes the cost of providing these benefits as payroll expense/expenditure in an operating fund with corresponding revenue in the Employee Benefits Fund. Medical and dental premiums and claims and life insurance premiums are reported in the Employee Benefits Fund. The estimated cost of providing these benefits for 2,298 retirees was $12.5 million in 2003, and $8.6 million in 2002 for 2,135 retirees.

As more fully described in Note 14, the City is a participant in the South Texas Project Nuclear Operating Company (STPNOC) and as such is liable for certain post-employment benefits for STPNOC employees. At December 31, 2002, the City's portion of this obligation, $3,774,761, is not reflected in the financial statements of the Electric Fund.

16 – SUBSEQUENT EVENTS

Airport System Revenue Bond Refunding Issue

In January 2004, the City issued $54,250,000 of Airport System Prior Lien Revenue Refunding Bonds, Series 2003. Proceeds from the bonds were used to refund $52,290,000 of Airport System Prior Lien Revenue Bonds, Series 1995A. The refunding resulted in future interest requirements to service the debt of $31,649,110. An economic gain of $3,132,423 was recognized on this transaction. The change in net cash flows that resulted was a decrease of $3,418,051. An accounting loss of $5,478,957, which will be deferred and amortized, was recognized on this refunding.

REQUIRED SUPPLEMENTARY INFORMATION

CITY OF AUSTIN
FOUNDED 1839

General Fund
Schedule of Revenues, Expenditures and Changes In Fund Balances--Budget and Actual-Budget Basis
For the year ended September 30, 2003
(In thousands)

	2003					
	Actual	Adjustments (1) (2)	Actual-Budget Basis	Budget Original	Budget Final	Variance Positive (Negative) (3)
REVENUES						
Taxes	$ 264,511	–	264,511	273,251	273,251	(8,740)
Franchise fees	28,962	–	28,962	28,287	28,287	675
Fines, forfeitures and penalties	16,966	–	16,966	17,458	17,458	(492)
Licenses, permits and inspections	14,737	–	14,737	15,771	15,771	(1,034)
Charges for services/goods	15,403	(1,201)	14,202	13,223	13,223	979
Interest and other	19,815	(4,975)	14,840	14,251	14,251	589
Total revenues	360,394	(6,176)	354,218	362,241	362,241	(8,023)
EXPENDITURES						
General government						
Municipal Court	8,909	(78)	8,831	8,986	8,986	155
Public safety						
Police	152,881	(1,857)	151,024	155,166	155,166	4,142
Fire	82,662	(737)	81,925	81,126	82,517	592
Emergency Medical Services	19,141	(111)	19,030	19,709	19,709	679
Transportation, planning and sustainability						
Public Works and Transportation	–	–	–	–	–	–
Transportation, Planning and Sustainability	9,201	(400)	8,801	10,083	10,083	1,282
Street lighting	179	–	179	100	100	(79)
Public health:						
Health	26,808	(146)	26,662	29,017	29,017	2,355
Physician stipend/charity care	10,501	1	10,502	10,502	10,502	–
Medical Assistance Program	8,752	–	8,752	8,396	8,396	(356)
Social services management	9,985	(82)	9,903	10,297	10,297	394
Public recreation and culture						
Parks and Recreation	28,170	174	28,344	29,079	29,079	735
Austin Public Library	17,023	60	17,083	17,917	17,917	834
Urban growth management						
Development Services and Watershed Protection	8,379	(27)	8,352	8,573	8,573	221
Neighborhood Planning and Zoning	3,259	(21)	3,238	3,999	3,999	761
General city responsibilities (4)	47,029	(35,700)	11,329	13,654	13,654	2,325
Total expenditures	432,879	(38,924)	393,955	406,604	407,995	14,040
Excess (deficiency) of revenues over expenditures	(72,485)	32,748	(39,737)	(44,363)	(45,754)	6,017
OTHER FINANCING SOURCES (USES)						
Capital leases	785	(785)	–	–	–	–
Transfers in	92,417	1,201	93,618	93,618	93,618	–
Transfers out	(21,129)	(39,726)	(60,855)	(70,012)	(70,012)	9,157
Total other financing sources (uses)	72,073	(39,310)	32,763	23,606	23,606	9,157
Excess (deficiency) of revenues and other sources over expenditures and other uses	(412)	(6,562)	(6,974)	(20,757)	(22,148)	15,174
Fund balance at beginning of year	93,618	(52,292)	41,326	34,245	34,245	7,081
Fund balance at end of year	$ 93,206	(58,854)	34,352	13,488	12,097	22,255

(1) Includes adjustments to expenditures for current year encumbrances, payments against prior year encumbrances, accrued payroll, compensated absences, and amounts budgeted as operating transfers.
(2) Includes adjustments to revenues/transfers required for adjusted budget basis presentation.
(3) Variance is actual-budget basis to final budget.
(4) Actual expenditures include employee training costs and amounts budgeted as fund-level expenditures or operating transfers. Actual-budget basis expenditures include employee training costs, budgeted payroll accrual, and amounts budgeted as fund-level expenditures.

BUDGET BASIS REPORTING

a -- General

The City of Austin prepares its annual operating budget based on cash and available resources (budget basis) which differs from generally accepted accounting principles (GAAP basis). In governmental funds, encumbrances constitute the equivalent of expenditures for budgetary purposes. In order to provide a meaningful comparison of actual results to the budget, the Schedule of Revenues, Expenditures and Changes in Fund Balances -- Budget and Actual-Budget Basis for the General Fund presents the actual and actual-budget basis amounts in comparison with original and final budgets.

b -- Reconciliation of GAAP Basis and Budget Basis Amounts

The primary differences between GAAP-basis and budget reporting for the General Fund are the reporting of encumbrances and the reporting of certain operating transfers. General Fund accrued payroll is recorded at the department level on a GAAP basis and as an expenditure in the general city responsibilities activity on the budget basis. Adjustments necessary to convert the excess revenues and other sources over expenditures and other uses on a GAAP basis to a budget basis for the General Fund are provided, as follows (in thousands):

	General Fund
Excess (deficiency) of revenues and other sources over expenditures and other uses - GAAP basis	$ (412)
Adjustments - increases (decreases) due to:	
Outstanding encumbrances established in current year	(3,491)
Payments against prior year encumbrances	3,905
Tax anticipation notes	(4,800)
Advance from Airport Fund	(700)
Budgeted transfer for contingency reserve	(1,410)
Other	(66)
Excess (deficiency) of revenues and other sources over expenditures and other uses - budget basis	$ (6,974)

c -- Budget Amendments

The original budget of the General Fund was amended once during fiscal year 2003 for increased public safety costs.

The original and amended budget is presented in the accompanying financial statements. The General Fund budget includes other revenues and requirements, which are presented in the general city responsibilities category. The amended expenditure budget for these general city requirements includes the following: tuition reimbursement ($85,000), accrued payroll ($2,207,000), expenditures for workers' compensation ($7,861,811) and liability reserve ($3,500,000).

CITY OF AUSTIN
FOUNDED 1839

COMBINING FINANCIAL STATEMENTS AND SUPPLEMENTAL INFORMATION

GENERAL FUND

General Fund
Schedule of Revenues - Budget and Actual-Budget Basis
For the year ended September 30, 2003
(In thousands)

City of Austin, Texas
Exhibit E-1

	2003				
	Actual	Adjustments (1)	Actual-Budget Basis	Budget	Variance-Positive (Negative)
Taxes					
Property taxes:					
Current	$ 148,335	–	148,335	150,321	(1,986)
Delinquent	1,133	–	1,133	450	683
Penalty and interest	910	–	910	699	211
Sales taxes	110,454	–	110,454	117,929	(7,475)
Other taxes	3,679	–	3,679	3,852	(173)
Total taxes	264,511	–	264,511	273,251	(8,740)
Franchise fees	28,962	–	28,962	28,287	675
Fines, forfeitures and penalties					
Library fines	541	–	541	443	98
Traffic fines	7,600	–	7,600	8,580	(980)
Parking violations	2,652	–	2,652	2,549	103
Weights and measures	135	–	135	95	40
Other	6,038	–	6,038	5,791	247
Total fines, forfeitures and penalties	16,966	–	16,966	17,458	(492)
Licenses, permits and inspections					
Parking meters	2,125	–	2,125	1,995	130
Alarm permits	1,657	–	1,657	1,505	152
Commercial solid waste	751	–	751	742	9
Public health	1,810	–	1,810	1,504	306
Development	1,635	–	1,635	1,805	(170)
Building safety	6,215	–	6,215	7,671	(1,456)
Beer and wine permits	266	–	266	246	20
Other	278	–	278	303	(25)
Total licenses, permits and inspections	14,737	–	14,737	15,771	(1,034)
Charges for services/goods					
Recreation and culture	1,967	–	1,967	2,040	(73)
Public health	1,411	–	1,411	1,233	178
Emergency medical services	9,963	–	9,963	9,060	903
General government	2,062	(1,201)	861	890	(29)
Total charges for services/goods	15,403	(1,201)	14,202	13,223	979
Interest and other					
Interest	4,462	–	4,462	4,343	119
Rental income	8,711	–	8,711	8,463	248
Sale of property	366	–	366	167	199
Other	6,276	(4,975)	1,301	1,278	23
Total interest and other	19,815	(4,975)	14,840	14,251	589
Nondepartmental revenues	–	–	–	–	–
Total revenues	$ 360,394	(6,176)	354,218	362,241	(8,023)

(1) Adjustments and actual-budget basis include amounts budgeted as fund-level revenues.

General Fund
Schedule of Expenditures - Budget and Actual-Budget Basis
For the year ended September 30, 2003
(In thousands)

City of Austin, Texas
Exhibit E-2

	2003				
	Actual	Adjustments (1)	Actual-Budget Basis	Budget	Variance-Positive (Negative)
Administration					
Municipal Court:					
Salaries and fringe benefits	$ 7,097	(26)	7,071	7,252	181
Contractual services	1,630	(47)	1,583	1,547	(36)
Commodities	188	(2)	186	189	3
Expense refunds	(9)	--	(9)	(2)	7
Capital outlay	3	(3)	--	--	--
Total administration	8,909	(78)	8,831	8,986	155
Public safety					
Police:					
Salaries and fringe benefits	144,047	(977)	143,070	142,918	(152)
Contractual services	13,556	(365)	13,191	13,652	461
Commodities	2,514	49	2,563	3,854	1,291
Expense refunds	(8,958)	(326)	(9,284)	(6,661)	2,623
Capital outlay	1,722	(238)	1,484	1,403	(81)
	152,881	(1,857)	151,024	155,166	4,142
Fire:					
Salaries and fringe benefits	80,809	(519)	80,290	80,126	(164)
Contractual services	4,597	(53)	4,544	5,120	576
Commodities	1,177	(159)	1,018	1,231	213
Indirect cost	293	--	293	238	(55)
Expense refunds	(4,263)	--	(4,263)	(4,248)	15
Capital outlay	49	(6)	43	50	7
	82,662	(737)	81,925	82,517	592
Emergency Medical Services:					
Salaries and fringe benefits	16,286	(103)	16,183	16,418	235
Contractual services	1,898	8	1,906	1,940	34
Commodities	852	102	954	1,176	222
Expense refunds	(282)	--	(282)	(273)	9
Capital outlay	387	(118)	269	448	179
	19,141	(111)	19,030	19,709	679
Total public safety	254,684	(2,705)	251,979	257,392	5,413
Transportation, planning, and sustainability					
Public Works and Transportation:					
Street lighting	179	--	179	100	(79)
	179	--	179	100	(79)
Transportation, Planning and Sustainability:					
Salaries and fringe benefits	9,354	(31)	9,323	9,757	434
Contractual services	1,948	(78)	1,870	2,319	449
Commodities	577	12	589	988	399
Indirect cost	570	--	570	564	(6)
Expense refunds	(3,553)	--	(3,553)	(3,567)	(14)
Capital outlay	305	(303)	2	22	20
	9,201	(400)	8,801	10,083	1,282
Total transportation, planning and sustainability	$ 9,380	(400)	8,980	10,183	1,203

(Continued)

	2003				
	Actual	Adjustments (1)	Actual-Budget Basis	Budget	Variance-Positive (Negative)
Public health					
Health and Human Services:					
Physician stipend/charity care	$ 10,501	1	10,502	10,502	--
Medical Assistance Program -- hospital contracted services/ patient services	8,752	--	8,752	8,396	(356)
Other public health					
Salaries and fringe benefits	15,304	(67)	15,237	15,468	231
Contractual services	11,609	49	11,658	13,285	1,627
Commodities	951	--	951	1,240	289
Expense refunds	(1,186)	--	(1,186)	(979)	207
Capital outlay	130	(128)	2	3	1
Other public health	26,808	(146)	26,662	29,017	2,355
Total public health	46,061	(145)	45,916	47,915	1,999
Public recreation and culture					
Parks and Recreation:					
Salaries and fringe benefits	21,955	(68)	21,887	23,188	1,301
Contractual services	7,254	139	7,393	6,651	(742)
Commodities	1,385	165	1,550	2,101	551
Indirect cost	265	--	265	424	159
Expense refunds	(2,875)	--	(2,875)	(3,427)	(552)
Capital outlay	186	(62)	124	142	18
	28,170	174	28,344	29,079	735
Austin Public Library:					
Salaries and fringe benefits	13,251	(64)	13,187	13,598	411
Contractual services	1,953	4	1,957	2,502	545
Commodities	2,030	144	2,174	1,929	(245)
Expense refunds	(235)	--	(235)	(169)	66
Capital outlay	24	(24)	--	57	57
	17,023	60	17,083	17,917	834
Total public recreation and culture	$ 45,193	234	45,427	46,996	1,569

(Continued)

General Fund
Schedule of Expenditures - Budget and Actual-Budget Basis
For the year ended September 30, 2003
(In thousands)

City of Austin, Texas
Exhibit E-2
(Continued)

	2003				
	Actual	Adjustments (1)	Actual-Budget Basis	Budget	Variance-Positive (Negative)
Urban growth management					
Neighborhood Planning & Zoning:					
Salaries and fringe benefits	$ 2,650	(7)	2,643	3,096	453
Contractual services	562	6	568	807	239
Commodities	29	(2)	27	96	69
Capital outlay	18	(18)	–	–	–
	3,259	(21)	3,238	3,999	761
Development Services and Watershed Protection:					
Salaries and fringe benefits	7,460	(54)	7,406	7,734	328
Contractual services	1,580	32	1,612	1,894	282
Commodities	64	(5)	59	107	48
Expense refunds	(725)	–	(725)	(1,183)	(458)
Capital outlay	–	–	–	21	21
	8,379	(27)	8,352	8,573	221
Total urban growth management	11,638	(48)	11,590	12,572	982
Social services management	9,985	(82)	9,903	10,297	394
General city responsibilities (2)	47,029	(35,700)	11,329	13,654	2,325
Total expenditures	432,879	(38,924)	393,955	407,995	14,040
General fund expenditures					
Salaries	318,213	(1,916)	316,297	319,555	3,258
Contractuals	65,840	(304)	65,536	68,615	3,079
Commodities	9,767	304	10,071	12,911	2,840
Indirect cost	1,128	–	1,128	1,226	98
Expense refunds	(22,086)	(326)	(22,412)	(20,509)	1,903
Capital outlay	2,824	(900)	1,924	2,146	222
Street lighting	179	–	179	100	(79)
Social services management	9,985	(82)	9,903	10,297	394
General city responsibilities	47,029	(35,700)	11,329	13,654	2,325
Total expenditures	$ 432,879	(38,924)	393,955	407,995	14,040

(1) Includes adjustments for current year encumbrances, payments against prior year encumbrances, accrued payroll, compensated absences and amounts budgeted as operating transfers or fund-level expenditures.

(2) Actual expenditures include employee training costs and amounts budgeted as fund-level expenditures or operating transfers. Actual-budget basis expenditures include employee training costs, budgeted payroll accrual, and amounts budgeted as fund-level expenditures.

General Fund
Schedule of Transfers - Budget and Actual-Budget Basis
For the year ended September 30, 2003
(In thousands)

City of Austin, Texas
Exhibit E-3

	2003				
	Actual	Adjustments (1)	Actual-Budget Basis	Budget	Variance-Positive (Negative)
Transfers In					
Enterprise funds:					
Electric	$ 72,864	–	72,864	72,864	–
Water and Wastewater	19,553	1,201	20,754	20,754	–
Total transfers In	92,417	1,201	93,618	93,618	–
Transfers out					
General fund:					
Contingency reserve	–	1,410	1,410	4,000	2,590
Special revenue funds:					
Neighborhood Housing and Conservation	995	–	995	1,020	25
Barton Springs Conservation	45	–	45	45	–
Sustainability Fund	4,406	–	4,406	4,968	562
Tax Increment Finance	100	–	100	100	–
Tourism and Promotion	125	–	125	125	–
Capital project funds	6,952	–	6,952	9,452	2,500
Enterprise funds:					
Airport	–	700	700	700	–
Drainage	299	–	299	299	–
Primary Care	7,729	–	7,729	7,729	–
Solid Waste Services	478	–	478	478	–
Internal service funds:					
Capital Projects Management	–	1,816	1,816	1,816	–
Fleet Maintenance	–	1,533	1,533	3,286	1,753
Information Systems	–	14,550	14,550	15,074	524
Support Services	–	19,275	19,275	20,463	1,188
Wireless Communication	–	290	290	305	15
Fiduciary funds:					
Voluntary Utility Assistance	–	152	152	152	–
Total transfers out	21,129	39,726	60,855	70,012	9,157
Net transfers	$ 71,288	(38,525)	32,763	23,606	9,157

(1) Includes adjustments to actual transfers required for adjusted budget basis presentation.

CITY OF AUSTIN
FOUNDED 1839

NONMAJOR GOVERNMENTAL FUNDS

CITY OF AUSTIN
FOUNDED 1839

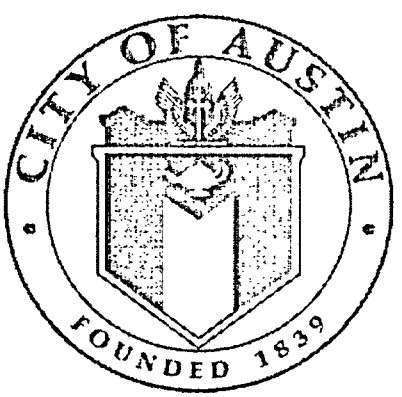
Nonmajor Governmental Funds
Combining Balance Sheet
September 30, 2003
(In thousands)

City of Austin, Texas
Exhibit E-4

	Special Revenue	Debt Service	Capital Projects	Permanent Funds	2003 Total
ASSETS					
Cash	$ 5	–	–	–	5
Pooled investments and cash	46,168	269	119,255	1,353	167,045
Investments, at fair value	936	13,749	–	–	14,685
Cash held by trustee	9,791	–	–	–	9,791
Property taxes receivable	–	4,302	–	–	4,302
Less allowance for uncollectible taxes	–	(697)	–	–	(697)
Net property taxes receivable	–	3,605	–	–	3,605
Accounts and other taxes receivable	14,421	2	82,547	–	96,970
Less allowance for doubtful accounts	(247)	–	(139)	–	(386)
Net accounts receivable	14,174	2	82,408	–	96,584
Receivables from other governments	12,586	–	–	–	12,586
Notes receivable, net of allowance	9,016	–	–	–	9,016
Due from other funds	14,503	6	22,416	–	36,925
Advances to other funds	–	4,677	–	–	4,677
Real property held for resale	5,984	–	–	–	5,984
Prepaid expenses	2	9	–	–	11
Other assets	717	–	413	–	1,130
Total assets	113,882	22,317	224,492	1,353	362,044
LIABILITIES AND FUND BALANCES					
Accounts payable	6,175	–	11,649	–	17,824
Accrued payroll	49	–	–	–	49
Accrued compensated absences	6	–	–	–	6
Due to other funds	14,503	–	22,416	–	36,919
Deferred revenue	2,824	3,458	–	–	6,282
Advances from other funds	–	248	–	–	248
Deposits and other liabilities	45,848	1,300	1,319	–	48,467
Total liabilities	69,405	5,006	35,384	–	109,795
Fund balances					
Reserved:					
Encumbrances	4,089	–	84,666	–	88,755
Notes receivable	9,016	–	–	–	9,016
Real property held for resale	5,984	–	–	–	5,984
Debt service	–	17,311	–	–	17,311
Permanent funds	–	–	–	1,040	1,040
Unreserved, designated:					
Special revenue	25,388	–	–	–	25,388
Unreserved, undesignated:					
Capital projects	–	–	104,442	–	104,442
Permanent funds	–	–	–	313	313
Total fund balances	44,477	17,311	189,108	1,353	252,249
Total liabilities and fund balances	$ 113,882	22,317	224,492	1,353	362,044

Nonmajor Governmental Funds | **City of Austin, Texas**
Combining Statement of Revenues, Expenditures and Changes in Fund Balances | **Exhibit E-5**
For the year ended September 30, 2003
(In thousands)

	Special Revenue	Debt Service	Capital Projects	Permanent Funds	2003 Total
REVENUES					
Property taxes	$ –	82,195	–	–	82,195
Franchise fees and other taxes	30,409	–	–	–	30,409
Fines, forfeitures and penalties	3,475	525	–	–	4,000
Charges for services/goods	24,463	–	–	–	24,463
Intergovernmental	59,573	–	14,819	–	74,392
Property owners' participation and contributions	–	–	10,935	2	10,937
Interest and other	1,241	5,250	3,412	27	9,930
Total revenues	119,161	87,970	29,166	29	236,326
EXPENDITURES					
Current:					
General government	1,019	–	–	–	1,019
Public safety	14,820	–	–	–	14,820
Transportation, planning and sustainability	3,776	–	–	–	3,776
Public health	23,864	–	–	–	23,864
Public recreation and culture	5,893	–	–	–	5,893
Urban growth management	47,321	–	–	–	47,321
Debt service:					
Principal	–	49,340	–	–	49,340
Interest	–	38,529	–	–	38,529
Fees and commissions	–	8	–	–	8
Capital outlay	–	–	155,517	–	155,517
Total expenditures	96,693	87,877	155,517	–	340,087
Excess (deficiency) of revenues over expenditures	22,468	93	(126,351)	29	(103,761)
OTHER FINANCING SOURCES (USES)					
Issuance of tax supported debt	–	–	70,323	–	70,323
Issuance of refunding bonds	–	62,514	–	–	62,514
Payment to escrow agent	–	(62,514)	–	–	(62,514)
Capital leases	106	–	–	–	106
Transfers in	17,935	767	18,139	–	36,841
Transfers out	(36,077)	–	(4,970)	–	(41,047)
Total other financing sources (uses)	(18,036)	767	83,492	–	66,223
Net change in fund balances	4,432	860	(42,859)	29	(37,538)
Fund balances at beginning of year	40,045	16,451	231,967	1,324	289,787
Fund balances at end of year	$ 44,477	17,311	189,108	1,353	252,249


CITY OF AUSTIN
FOUNDED 1839

SPECIAL REVENUE FUNDS

Special revenue funds are used to account for the proceeds of specific revenue sources (other than major capital projects) that are legally restricted to expenditures for specific purposes. Included in the special revenue funds are:

Federal, State, and other special revenue grant funds;
Other special revenue funds - see below for descriptions of the individual funds;
Housing Assistance fund – provides housing assistance to the citizens of Austin.

Other Special Revenue Funds

General Government

Municipal Court:

Municipal Court Building Security Fund – Provides funding to enhance courthouse security.

Municipal Court Technology Fund - Provides funding for technological enhancements to Municipal Court operations.

Public Safety

Police:

APD Incident Management Fund – Accounts for funds from Capital Metro to the Austin Police Dept. to establish a traffic command center within the APD.

Auto Theft Interdiction Fund – Accounts for funds seized related to current auto theft investigations.

Aviation Asset Forfeiture Fund - Accounts for the redistribution of proceeds generated by airport police enforcement activities.

Police Benefit Fund – Accounts for donations received for the benefit and improvement of the Police Department.

Police Federal Seized Funds Fund - Records all federal seized funds generated by police enforcement activities per State Code of Criminal Procedures (Chapter 59).

Police Seized Money Fund - Accounts for the redistribution of proceeds generated by police enforcement activities.

Fire:

Fire Miscellaneous Fund - Accounts for contributions for "The Firehouse," a public safety awareness exhibit, which is transported to different sites throughout Austin.

Emergency Medical Services:

EMS Travis County Reimbursed Fund – Accounts for expenses incurred in providing for expanded emergency medical services to the citizens of Travis County, located outside the City of Austin and the corresponding reimbursements from Travis County.

Transportation, Planning, and Sustainability

Public Works and Transportation:

Fiscal Surety - Land Development Fund - Escrow funds received from contractors for hydromulch and erosion control.

Office of Emergency Management Miscellaneous Fund - Accounts for contributions for public safety awareness.

Recycle Bins Fund – Accounts for donations from citizens and businesses to help defray cost of purchasing recycle bins/containers.

RMD Conservation Fund - Monies contributed by the Electric Fund to be used for energy loans and rebates/incentives to customers.

RMD Loan Fund - Accounts for energy loans to customers.

Transportation, Planning, and Sustainability:

Austin Transportation Study Fund - Accounts for a transportation study regarding the Austin Metropolitan roadways, bicycle areas, and pedestrian's walkways.

Child Safety Fund - Accounts for certain fines and fees used to provide school crossing guards at City schools.

Environmental Remediation Fund - Accounts for remediation of sites, which affect ground and surface water quality or public health and safety.

Pavement Life Recovery Cost Fee Fund - Collection of fees associated with pavement life recovery costs.

Railroad Right of Way Fund - Accounts for the City's management of the Austin and Northwestern Railroad right of way.

Subdivision Participation Fund - Escrow account for funds received from contractors for construction and installation of streets, sidewalks, drainage facilities, etc.

Public Health

Health and Human Services:

Disproportionate Share Fund - Used to purchase medical equipment and fund structural changes for the clinic system of the Austin/Travis County Health Department in order to serve indigent patients.

Health and Human Services Travis County Reimbursed Fund - Accounts for expenses incurred by the City on behalf of Travis County and the corresponding reimbursement from Travis County for Health and Human Services and Federally Qualified Health Center programs.

Health Miscellaneous Fund - Accounts for contributions for Strategic Intervention for High Risk Youth.

Medicaid Administrative Claims Fund - Holds additional Medicaid proceeds.

Other Public Health:

Animal Shelter Building Fund - Accounts for donations to improve the Townlake Animal Shelter.

Other Special Revenue Funds

Public Recreation and Culture

Austin Public Library:

Austin History Center Fund – Accounts for contributions to be used for the Austin-Travis County Collection.

Julia Cousins Trust Fund – Accounts for funds received from the estate of Julia Cousins to purchase books for the public library.

Miscellaneous Library Fund – Accounts for miscellaneous deposits primarily related to Massie Library.

Special Library Trust Fund – Accounts for donations received to purchase books or special equipment.

Parks and Recreation:

Adaptive Programs Fund – Accounts for various revenues and fees generated by programs and activities sponsored by the Parks and Recreation Dept.

Austin Creeks and Trails Fund – Accounts for donations received for the upkeep of Austin's creeks and trails.

Balcones Canyonlands Fund – Accounts for an endowment to be used for long-term monitoring and management of the Bohls tract.

Friends of East Austin Youth Fund - Accounts for donations from the Friends of East Austin Youth Golf Tournament to fund programs benefiting the youth of East Austin.

PARD Cultural Projects Fund - Records activities for cultural project purposes. Funded by a portion of the bed tax.

PARD Miscellaneous Fund – Accounts for miscellaneous deposits and revenues to be used for specified purposes.

PARD Police Asset Forfeiture Fund - Accounts for the redistribution of proceeds generated by PARD police enforcement activities.

Planting for the Future Fund – Accounts for donations received for plantings in the City of Austin.

Republic Square Fund – Accounts for donations for the improvement and beautification of Republic Square.

Rifle Class Fund – Accounts for fee revenue received by individuals for instruction, materials, and supplies for rifle classes.

Senior Citizen Nutrition Fund – Accounts for donations received at various senior citizen luncheon sites around the City.

Summer Musical Fund – Accounts for the annual summer musical production that is administered by the Parks and Recreation Department.

Teen Activity Fund – Accounts for contributions received to provide leisure activities for teenagers.

Tennis League Fund – Accounts for tournament fees received by participants of Austin Tennis League activities and tournaments.

Town Lake Beautification Fund – Accounts for donations for the beautification of Town Lake.

Urban Growth Management

Neighborhood Housing & Community Development:

Housing Miscellaneous Fund - Accounts for donations to the Housing program to be used for specific purposes.

Housing Trust Social Equity Fund – Accounts for housing funds set aside for SMART Housing initiative.

Neighborhood Housing and Conservation Fund - Established in 1996 to lead economic development, affordable housing, and neighborhood revitalization efforts.

Development Services and Watershed Protection:

Austin Industrial Development Corporation Fund (AIDC) - Accounts for the administrative costs related to the Corporation.

Austin Inner City Redevelopment Corporation Fund - Accounts for the activity of this entity.

Energy Conservation Rebates and Incentives Fund - Used for energy loans and rebates/incentives to customers; funded primarily by Electric Fund.

Fee Waiver Fund - Accounts for funds provided to allow for payment of fees waived by Council through City Ordinance.

Planning, Environmental Conservation Services Fund - Accounts for energy and water conservation services and environmental protection activities; funding provided by transfers from General, Electric, Water and Wastewater and other funds.

Public Improvement District Fund - Accounts for the downtown public improvement district which will provide services, security, and improvements for the downtown Austin area.

Urban Forest Replenishment Fund – Assists in planting replacement trees, saving blocks of natural areas, providing a maintenance program for trees to be retained, requiring special construction techniques, and/or transplanting existing trees.

Other:

Barton Springs Conservation Fund - Accounts for habitat conservation in Barton Springs.

Cable TV Fund - Payments cable companies and disbursement to Austin Access Television.

Downtown Development Fund - Accounts for the relocation of music venue facilities.

Hotel-Motel Occupancy Tax Fund - Accounts for hotel/motel occupancy tax revenues and transfers of these revenues to participating funds.

Music Loan Program Fund – Provides resources for one-time music projects.

One Texas Center Fund – Accounts for the revenues and debt service requirements of the One Texas Center Building.

RMMA Reimbursement Fund – Accounts for the expenses incurred by the City for the redevelopment of the former Robert Mueller Municipal Airport (RMMA) site and the corresponding reimbursements by the Catellus Development Corp

Strategic Planning Investment Fund - Accounts for costs related to managing and planning for growth by the City of Austin.

Sustainability Fund – Provides resources for one-time projects that will help the City of Austin build a sustainable economic, environmental, and equitable infrastructure.

Tax Increment Finance Fund – Accounts for maintaining the plazas, streetscapes and other public improvements installed on specific downtown Blocks.

Tourism and Promotion Fund - Accounts for the promotion of tourism in Austin as both a leisure and business destination. Funded by a portion of bed tax receipts.

Vehicle Rental Tax Fund - Accounts for the levy of a short-term motor vehicle rental tax.

Wildland Conservation Fund - Accounts for the City and county's management of preserve systems.

Special Revenue Funds
Combining Balance Sheet
September 30, 2003
(In thousands)

City of Austin, Texas
Exhibit E-6

	Federal, State, and Other Special Revenue Grants	Other Special Revenue Funds	Housing Assistance	Total
ASSETS				
Cash	$ –	5	–	5
Pooled investments and cash	4,991	40,027	1,150	46,168
Investments, at fair value	–	–	936	936
Cash held by trustee	9,791	–	–	9,791
Accounts and other taxes receivable	–	11,859	2,562	14,421
Less allowance for doubtful accounts	–	–	(247)	(247)
Net accounts receivable	–	11,859	2,315	14,174
Receivables from other governments	12,586	–	–	12,586
Notes receivable, net of allowance	–	–	9,016	9,016
Due from other funds	–	14,503	–	14,503
Real property held for resale	–	–	5,984	5,984
Prepaid expenses	–	2	–	2
Other assets	48	566	103	717
Total assets	27,416	66,962	19,504	113,882
LIABILITIES AND FUND BALANCES				
Accounts payable	2,302	3,153	720	6,175
Accrued payroll	–	49	–	49
Accrued compensated absences	–	6	–	6
Due to other funds	10,823	3,680	–	14,503
Deferred revenue	–	–	2,824	2,824
Deposits and other liabilities	14,291	30,872	685	45,848
Total liabilities	27,416	37,760	4,229	69,405
Fund balances				
Reserved:				
Encumbrances	–	4,089	–	4,089
Notes receivable	–	–	9,016	9,016
Real property held for resale	–	–	5,984	5,984
Unreserved, designated:				
Special revenue	–	25,113	275	25,388
Total fund balances	–	29,202	15,275	44,477
Total liabilities and fund balances	$ 27,416	66,962	19,504	113,882

Special Revenue Funds **City of Austin, Texas**
Combining Statement of Revenues, Expenditures and Changes in Fund Balances **Exhibit E-7**
For the year ended September 30, 2003
(In thousands)

	Federal, State, and Other Special Revenue Grants	Other Special Revenue Funds	Housing Assistance	Total
REVENUES				
Franchise fees and other taxes	$ –	30,409	–	30,409
Fines, forfeitures and penalties	–	3,475	–	3,475
Charges for services/goods	–	24,463	–	24,463
Intergovernmental	46,758	2,428	10,387	59,573
Interest and other	–	624	617	1,241
Total revenues	46,758	61,399	11,004	119,161
EXPENDITURES				
Current:				
General government	293	726	–	1,019
Public safety	6,313	8,507	–	14,820
Transportation, planning and sustainability	1,177	2,599	–	3,776
Public health	18,974	4,890	–	23,864
Public recreation and culture	2,637	3,256	–	5,893
Urban growth management	17,364	20,714	9,243	47,321
Total expenditures	46,758	40,692	9,243	96,693
Excess (deficiency) of revenues over expenditures	–	20,707	1,761	22,468
OTHER FINANCING SOURCES (USES)				
Capital leases		102	4	106
Transfers in	–	17,935	–	17,935
Transfers out	–	(36,077)	–	(36,077)
Total other financing sources (uses)	–	(18,040)	4	(18,036)
Net change in fund balances	–	2,667	1,765	4,432
Fund balances at beginning of year	–	26,535	13,510	40,045
Fund balances at end of year	$ –	29,202	15,275	44,477

Special Revenue Funds
Combining Balance Sheet - All Special Revenue Grants
September 30, 2003
(In thousands)

City of Austin, Texas
Exhibit E-8

	Assets					Liabilities and Fund Balances					
	Pooled Investments and Cash	Cash held by trustee	Receivables from Other Governments	Other Assets	Total Assets	Accounts Payable	Due to Other Funds	Other Liabilities	Total Liabilities	Fund Balances	Total Liabilities and Fund Balances
FEDERAL GRANTS											
U.S. Department of Agriculture	$ --	--	989	--	989	18	971	--	989	--	989
Corporation for National and Community Service	--	--	141	--	141	36	105	--	141	--	141
Equal Employment Opportunity Commission	--	--	--	--	--	--	--	--	--	--	--
U.S. Department of Justice	218	--	940	--	1,158	201	885	72	1,158	--	1,158
U.S. Department of Labor	--	--	26	--	26	--	26	--	26	--	26
U.S. Department of Transportation	9	--	529	--	538	--	529	9	538	--	538
U.S. Federal Emergency Management	45	--	77	--	122	4	73	45	122	--	122
U.S. Health & Human Services	1,157	--	3,290	12	4,459	938	2,411	1,110	4,459	--	4,459
U.S. Housing/Urban Development	3,192	9,791	5,191	30	18,204	1,015	4,492	12,697	18,204	--	18,204
U.S. National Foundation on the Arts and Humanities	21	--	353	6	380	21	348	11	380	--	380
U.S. Department of Veterans Affairs	152	--	--	--	152	2	--	150	152	--	152
Total Federal Grants	4,794	9,791	11,536	48	26,169	2,235	9,840	14,094	26,169	--	26,169
STATE GRANTS											
Texas Governor's Office Criminal Justice Division	--	--	262	--	262	39	223	--	262	--	262
Texas Health Department	29	--	197	--	226	10	186	30	226	--	226
Office of the Attorney General	--	--	47	--	47	--	47	--	47	--	47
Texas Comptroller of Public Accounts	94	--	--	--	94	1	--	93	94	--	94
Texas Health and Human Services Commission	1	--	--	--	1	--	--	1	1	--	1
Texas Parks and Wildlife	--	--	88	--	88	--	88	--	88	--	88
Texas Department of Transportation	--	--	242	--	242	12	230	--	242	--	242
The University of Texas at Austin Center of Criminology	1	--	--	--	1	--	--	1	1	--	1
Texas State Library and Archives Commission	--	--	57	--	57	5	52	--	57	--	57
State Energy Conservation Office	--	--	13	--	13	--	13	--	13	--	13
Total State Grants	125	--	906	--	1,031	67	839	125	1,031	--	1,031
OTHER SPECIAL REVENUE GRANTS	72	--	144	--	216	--	144	72	216	--	216
Total All Grants	$ 4,991	9,791	12,586	48	27,416	2,302	10,823	14,291	27,416	--	27,416

Special Revenue Funds
Combining Statement of Revenues, Expenditures and Changes in Fund Balances - All Special Revenue Grants
For the year ended September 30, 2003
(In thousands)

	Revenues: Inter-governmental	Expenditures: Special Projects	Excess (Deficiency) Of Revenues Ove- Expenditures	Fund Balances at Beginning of Year	Fund Balances at End of Year
FEDERAL GRANTS					
U.S. Department of Agriculture	$ 3,637	3,637	--	--	--
Corporation for National and Community Service	258	258	--	--	--
Equal Employment Opportunity Commission	77	77	--	--	--
U.S. Department of Justice	4,068	4,068	--	--	--
U.S. Department of Labor	280	280	--	--	--
U.S. Department of Transportation	1,632	1,632	--	--	--
U.S. Federal Emergency Management	246	246	--	--	--
U.S. Health & Human Services	10,441	10,441	--	--	--
U.S. Housing/Urban Development	22,128	22,128	--	--	--
U.S. National Foundation on the Arts and Humanities	1,387	1,387	--	--	--
U.S. Department of Veterans Affairs	50	50	--	--	--
Total Federal Grants	44,204	44,204	--	--	--
STATE GRANTS					
Texas Governor's Office Criminal Justice Division	385	385	--	--	--
Texas Health Department	760	760	--	--	--
Office of the Attorney General	138	138	--	--	--
Texas Comptroller of Public Accounts	39	39	--	--	--
Texas Health and Human Services Commission	72	72	--	--	--
Texas Parks and Wildlife	43	43	--	--	--
Texas Department of Transportation	425	425	--	--	--
The University of Texas at Austin Center of Criminology	--	--	--	--	--
Texas State Library and Archives Commission	117	117	--	--	--
State Energy Conservation Office	107	107	--	--	--
Total State Grants	2,086	2,086	--	--	--
OTHER SPECIAL REVENUE GRANTS	468	468	--	--	--
Total All Grants	$ 46,758	46,758	--	--	--

Special Revenue Funds
Combining Schedule of Expenditures - All Special Revenue Grants
From Inception to September 30, 2003
(In thousands)

City of Austin, Texas
Exhibit E-10

	Total Expenditures at Beginning of Year			Current Year		Total Expenditures at End of Year			Budget		
	Grant	In-Kind Match	Total	Grant	In-Kind Match	Grant	In-Kind Match	Total	Grant	In-Kind Match	Total
FEDERAL GRANTS											
U.S. Department of Agriculture	$ 2,995	59	3,054	3,637	(59)	6,632	--	6,632	5,489	11	5,500
Corporation for National and Community Service	--	--	--	258	86	258	86	344	400	86	486
Equal Employment Opportunity Commission	--	--	--	77	--	77	--	77	169	--	169
U.S. Department of Justice	1,423	238	1,661	4,068	1,026	5,491	1,264	6,755	9,598	7,002	16,600
U.S. Department of Labor	46	24	70	280	100	326	124	450	590	75	665
U.S. Department of Transportation	3,829	1,354	5,183	1,632	401	5,461	1,755	7,216	16,278	4,164	20,442
U.S. Federal Emergency Management	225	253	478	246	413	471	666	1,137	661	294	955
U.S. Health & Human Services	12,151	1,719	13,870	10,441	411	22,592	2,130	24,722	30,238	3,464	33,702
U.S. Housing/Urban Development	109,963	665	110,628	22,128	296	132,091	961	133,052	155,771	1,387	157,158
U.S. National Foundation on the Arts and Humanities	1,087	--	1,087	1,387	--	2,474	--	2,474	3,571	--	3,571
U.S. Department of Veterans Affairs	144	--	144	50	--	194	--	194	329	--	329
Total Federal Grants	131,863	4,312	136,175	44,204	2,674	176,067	6,986	183,053	223,094	16,483	239,577
STATE GRANTS											
Texas Governor's Office Criminal Justice Division	274	26	300	385	112	659	138	797	1,282	245	1,527
Texas Health Department	1,805	95	1,900	760	--	2,565	95	2,660	3,254	--	3,254
Office of the Attorney General	45	--	45	138	--	183	--	183	251	--	251
Texas Comptroller of Public Accounts	573	--	573	39	--	612	--	612	695	--	695
Texas Health and Human Services Commission	257	--	257	72	--	329	--	329	330	--	330
Texas Parks and Wildlife	58	--	58	43	35	101	35	136	100	25	125
Texas Department of Transportation	1,447	631	2,078	425	442	1,872	1,073	2,945	2,894	1,804	4,698
The University of Texas at Austin Center of Criminology	10	--	10	--	--	10	--	10	10	--	10
Texas State Library and Archives Commission	114	--	114	117	--	231	--	231	329	--	329
State Energy Conservation Office	33	--	33	107	19	140	19	159	209	19	228
Total State Grants	4,616	752	5,368	2,086	608	6,702	1,360	8,062	9,354	2,093	11,447
OTHER SPECIAL REVENUE GRANTS	838	25	863	468	--	1,306	25	1,331	1,807	40	1,847
Total All Grants	$ 137,317	5,089	142,406	46,758	3,282	184,075	8,371	192,446	234,255	18,616	252,871

Special Revenue Funds - Other
Combining Balance Sheet
September 30, 2003
(In thousands)

	Assets						
	Cash	Pooled Investments and Cash	Net Accounts Receivable	Due from Other Funds	Prepaid Expenses	Other Assets	Total Assets
General government							
Municipal Court:							
Municipal Court Building Security	$ –	158	–	–	–	–	158
Municipal Court Technology	–	1,782	–	–	–	–	1,782
Total general government	–	1,940	–	–	–	–	1,940
Public safety							
Police:							
APD Incident Management	–	362	–	–	–	–	362
Auto Theft Interdiction	–	25	–	–	–	–	25
Aviation Asset Forfeiture	–	190	–	–	–	–	190
Police Benefit	–	48	–	–	–	–	48
Police Federal Seized Funds	4	809	–	–	–	–	813
Police Seized Money	–	544	–	–	–	–	544
Total Police	4	1,978	–	–	–	–	1,982
Fire:							
Fire Miscellaneous	–	5	–	–	–	–	5
Total Fire	–	5	–	–	–	–	5
Emergency Medical Services:							
EMS Travis County Reimbursed	–	–	629	–	–	–	629
Total Emergency Medical Services	–	–	629	–	–	–	629
Total public safety	4	1,983	629	–	–	–	2,616
Transportation, planning and sustainability							
Public Works and Transportation:							
Fiscal Surety - Land Development	–	14,579	–	14,503	–	–	29,082
Office of Emergency Management Miscellaneous	–	1	–	–	–	–	1
Recycle Bins	–	5	–	–	–	–	5
RMD Conservation	–	97	–	–	–	–	97
RMD Loan	–	858	–	–	–	115	973
Total Public Works and Transportation	–	15,540	–	14,503	–	115	30,158
Transportation, Planning and Sustainability:							
Austin Transportation Study	–	–	1,069	–	–	–	1,069
Child Safety	–	512	–	–	–	–	512
Environmental Remediation	–	371	–	–	–	–	371
Pavement Life Recovery	–	141	21	–	–	–	162
Railroad Right of Way	–	5	–	–	–	–	5
Subdivision Participation	–	4,387	–	–	–	–	4,387
Total Transportation, Planning and Sustainability	–	5,416	1,090	–	–	–	6,506
Total transportation, planning and sustainability	$ –	20,956	1,090	14,503	–	115	36,664

Liabilities						Fund Balances				
Accounts Payable	Accrued Payroll	Accrued Compensated Absences	Due to Other Funds	Deposits and Other Liabilities	Total Liabilities	Reserved for Encumbrances	Unreserved Designated	Unreserved Undesignated	Total Fund Balances	Total Liabilities and Fund Balances
14	9	2	–	–	25	–	133	–	133	158
4	–	–	–	–	4	79	1,699	–	1,778	1,782
18	9	2	–	–	29	79	1,832	–	1,911	1,940
2	–	–	–	–	2	–	360	–	360	362
–	–	–	–	23	23	–	2	–	2	25
4	–	–	–	–	4	1	185	–	186	190
–	–	–	–	–	–	–	48	–	48	48
26	–	–	–	–	26	5	782	–	787	813
135	–	–	–	–	135	17	392	–	409	544
167	–	–	–	23	190	23	1,769	–	1,792	1,982
–	–	–	–	1	1	–	4	–	4	5
–	–	–	–	1	1	–	4	–	4	5
4	–	4	466	–	474	39	116	–	155	629
4	–	4	466	–	474	39	116	–	155	629
171	–	4	466	24	665	62	1,889	–	1,951	2,616
1,278	–	–	–	27,421	28,699	–	383	–	383	29,082
–	–	–	–	–	–	–	1	–	1	1
–	–	–	–	–	–	–	5	–	5	5
–	–	–	–	–	–	–	97	–	97	97
123	–	–	–	–	123	–	850	–	850	973
1,401	–	–	–	27,421	28,822	–	1,336	–	1,336	30,158
34	–	–	976	59	1,069	–	–	–	–	1,069
7	35	–	–	–	42	2	468	–	470	512
–	–	–	–	50	50	–	321	–	321	371
–	–	–	–	–	–	–	162	–	162	162
–	–	–	–	–	–	–	5	–	5	5
–	–	–	–	1,443	1,443	–	2,944	–	2,944	4,387
41	35	–	976	1,552	2,604	2	3,900	–	3,902	6,506
1,442	35	–	976	28,973	31,426	2	5,236	–	5,238	36,664

(Continued)

Special Revenue Funds - Other
Combining Balance Sheet
September 30, 2003
(In thousands)

	Assets						
	Cash	Pooled Investments and Cash	Net Accounts Receivable	Due from Other Funds	Prepaid Expenses	Other Assets	Total Assets
Public health							
Health and Human Services:							
Disproportionate Share	$ –	134	–	–	–	–	134
Health and Human Services Travis County Reimbursed	–	–	2,462	–	2	–	2,464
Health Miscellaneous	–	224	–	–	–	–	224
Medicaid Administrative Claims	–	796	–	–	–	–	796
Total Health and Human Services	–	1,154	2,462	–	2	–	3,618
Other public health:							
Animal Shelter Building	–	12	–	–	–	–	12
Total other public health	–	12	–	–	–	–	12
Total public health	–	1,166	2,462	–	2	–	3,630
Public recreation and culture							
Austin Public Library:							
Austin History Center	–	153	–	–	–	–	153
Julia Cousins Trust	–	1	–	–	–	–	1
Miscellaneous Library	–	1	–	–	–	–	1
Special Library	–	131	–	–	–	–	131
Total Austin Public Library	–	286	–	–	–	–	286
Parks and Recreation:							
Adaptive Programs	–	50	–	–	–	–	50
Austin Creeks and Trails	–	19	–	–	–	–	19
Balcones Canyonlands	–	75	–	–	–	–	75
Friends of East Austin Youth	–	10	–	–	–	–	10
PARD Cultural Projects	–	370	–	–	–	–	370
PARD Miscellaneous	–	589	–	–	–	–	589
PARD Police Asset Forfeitures	–	2	–	–	–	–	2
Planting for the Future	–	444	–	–	–	–	444
Republic Square	–	2	–	–	–	–	2
Rifle Class	–	1	–	–	–	–	1
Senior Nutrition	–	10	–	–	–	–	10
Summer Musical	–	100	–	–	–	–	100
Teen Activity	–	207	–	–	–	–	207
Tennis League	–	5	–	–	–	–	5
Town Lake Beautification	–	491	–	–	–	–	491
Total Parks and Recreation	–	2,375	–	–	–	–	2,375
Total public recreation and culture	$ –	2,661	–	–	–	–	2,661

(Continued)

Liabilities						Fund Balances				
Accounts Payable	Accrued Payroll	Accrued Compensated Absences	Due to Other Funds	Deposits and Other Liabilities	Total Liabilities	Reserved for Encumbrances	Unreserved Designated	Unreserved Undesignated	Total Fund Balances	Total Liabilities and Fund Balances
–	–	–	–	–	–	134	–	–	134	134
54	–	–	2,172	–	2,226	94	144	–	238	2,464
1	–	–	–	191	192	2	30	–	32	224
–	–	–	–	715	715	–	81	–	81	796
55	–	–	2,172	906	3,133	230	255	–	485	3,618
–	–	–	–	–	–	–	12	–	12	12
–	–	–	–	–	–	–	12	–	12	12
55	–	–	2,172	906	3,133	230	267	–	497	3,630
–	–	–	–	–	–	–	153	–	153	153
–	–	–	–	–	–	–	1	–	1	1
–	–	–	–	–	–	–	1	–	1	1
3	–	–	–	–	3	6	122	–	128	131
3	–	–	–	–	3	6	277	–	283	286
–	–	–	–	–	–	–	50	–	50	50
–	–	–	–	–	–	–	19	–	19	19
–	–	–	–	–	–	–	75	–	75	75
–	–	–	–	–	–	–	10	–	10	10
81	–	–	–	–	81	126	163	–	289	370
2	–	–	–	–	2	17	570	–	587	589
–	–	–	–	–	–	–	2	–	2	2
–	–	–	–	357	357	–	87	–	87	444
–	–	–	–	–	–	–	2	–	2	2
–	–	–	–	–	–	–	1	–	1	1
–	–	–	–	10	10	–	–	–	–	10
–	–	–	–	–	–	–	100	–	100	100
–	–	–	–	–	–	5	202	–	207	207
–	–	–	–	–	–	–	5	–	5	5
–	–	–	–	–	–	–	491	–	491	491
83	–	–	–	367	450	148	1,777	–	1,925	2,375
86	–	–	–	367	453	154	2,054	–	2,208	2,661

(Continued)

Special Revenue Funds - Other
Combining Balance Sheet
September 30, 2003
(In thousands)

	Assets						
	Cash	Pooled Investments and Cash	Net Accounts Receivable	Due from Other Funds	Prepaid Expenses	Other Assets	Total Assets
Urban growth management							
Neighborhood Housing & Community Development:							
Housing Miscellaneous	$ –	41	–	–	–	–	41
Housing Trust Social Equity	–	1,305	–	–	–	–	1,305
Neighborhood Housing and Conservation	1	1,607	–	–	–	–	1,608
Total Neighborhood Housing & Community Development	1	2,953	–	–	–	–	2,954
Development Services and Watershed Protection:							
Austin Industrial Development Corporation (AIDC)	–	149	–	–	–	–	149
Austin Inner City Redevelopment Corporation	–	2	–	–	–	–	2
Energy Conservation Rebates and Incentives	–	2,197	–	–	–	26	2,223
Fee Waiver	–	25	–	–	–	–	25
Planning, Environmental Conservation Services	–	108	–	–	–	–	108
Public Improvement District	–	1,114	15	–	–	–	1,129
Urban Forest Replenishment	–	124	–	–	–	–	124
Total Development Services and Watershed Protection	–	3,719	15	–	–	26	3,760
Other:							
Barton Springs Conservation	–	257	–	–	–	–	257
Cable TV	–	162	–	–	–	–	162
Downtown Development	–	184	–	–	–	–	184
Hotel-Motel Occupancy Tax	–	18	6,107	–	–	–	6,125
Music Loan Program	–	241	–	–	–	–	241
One Texas Center	–	1,544	–	–	–	–	1,544
RMMA Reimbursement	–	–	464	–	–	–	464
Strategic Planning Investment	–	25	–	–	–	–	25
Sustainability	–	517	–	–	–	–	517
Tax Increment Finance	–	190	–	–	–	–	190
Tourism and Promotion	–	–	–	–	–	425	425
Vehicle Rental Tax	–	–	1,092	–	–	–	1,092
Wildland Conservation	–	1,511	–	–	–	–	1,511
Total other	–	4,649	7,663	–	–	425	12,737
Total urban growth management	1	11,321	7,678	–	–	451	19,451
2003 Total	$ 5	40,027	11,859	14,503	2	566	66,962

(Continued)

Liabilities						Fund Balances				
Accounts Payable	Accrued Payroll	Accrued Compensated Absences	Due to Other Funds	Deposits and Other Liabilities	Total Liabilities	Reserved for Encumbrances	Unreserved Designated	Unreserved Undesignated	Total Fund Balances	Total Liabilities and Fund Balances
–	–	–	–	–	–	–	41	–	41	41
–	–	–	–	–	–	–	1,305	–	1,305	1,305
29	5	–	–	584	618	216	774	–	990	1,608
29	5	–	–	584	618	216	2,120	–	2,336	2,954
–	–	–	–	–	–	–	149	–	149	149
–	–	–	–	–	–	–	2	–	2	2
771	–	–	–	–	771	1,027	425	–	1,452	2,223
–	–	–	–	–	–	–	25	–	25	25
–	–	–	–	–	–	3	105	–	108	108
–	–	–	–	–	–	787	342	–	1,129	1,129
–	–	–	–	–	–	–	124	–	124	124
771	–	–	–	–	771	1,817	1,172	–	2,989	3,760
–	–	–	–	–	–	–	257	–	257	257
–	–	–	–	–	–	–	162	–	162	162
–	–	–	–	–	–	–	184	–	184	184
1	–	–	–	18	19	–	6,106	–	6,106	6,125
–	–	–	–	–	–	–	241	–	241	241
–	–	–	–	–	–	–	1,544	–	1,544	1,544
–	–	–	40	–	40	1,035	–	(611)	424	464
–	–	–	–	–	–	127	–	(102)	25	25
160	–	–	–	–	160	343	14	–	357	517
–	–	–	–	–	–	6	184	–	190	190
420	–	–	26	–	446	–	–	(21)	(21)	425
–	–	–	–	–	–	–	1,092	–	1,092	1,092
–	–	–	–	–	–	18	1,493	–	1,511	1,511
581	–	–	66	18	665	1,529	11,277	(734)	12,072	12,737
1,381	5	–	66	602	2,054	3,562	14,569	(734)	17,397	19,451
3,153	49	6	3,680	30,872	37,760	4,089	25,847	(734)	29,202	66,962

Special Revenue Funds - Other
Combining Statement of Revenues, Expenditures and Changes in Fund Balances
For the year ended September 30, 2003
(In thousands)

	Revenues					
	Gross Receipts Taxes	Fines, Forfeitures and Penalties	Charges for Services/ Goods	Contributions	Interest and Other	Total Revenues
General government						
Municipal Court:						
Municipal Court Building Security	$ –	468	–	–	3	471
Municipal Court Technology	–	609	–	–	32	641
Total general government	–	1,077	–	–	35	1,112
Public safety						
Police:						
APD Incident Management	–	–	–	–	463	463
Auto Theft Interdiction	–	–	–	–	–	–
Aviation Asset Forfeiture	–	4	–	–	4	8
Police Benefit	–	–	16	9	–	25
Police Federal Seized Funds	–	668	–	–	14	682
Police Seized Money	–	164	–	–	11	175
Total Police	–	836	16	9	492	1,353
Fire:						
Fire Miscellaneous	–	–	4	2	–	6
Total Fire	–	–	4	2	–	6
Emergency Medical Services:						
EMS Travis County Reimbursed	–	–	7,610	–	–	7,610
Total Emergency Medical Services	–	–	7,610	–	–	7,610
Total public safety	–	836	7,630	11	492	8,969
Transportation, planning and sustainability						
Public Works and Transportation:						
Fiscal Surety - Land Development	–	–	–	–	(231)	(231)
Office of Emergency Management Miscellaneous	–	–	3	–	–	3
Recycle Bins	–	–	–	–	–	–
RMD Conservation	–	–	–	–	–	–
RMD Loan	–	–	–	–	–	–
Total Public Works and Transportation	–	–	3	–	(231)	(228)
Transportation, Planning and Sustainability:						
Austin Transportation Study	–	–	1,519	–	–	1,519
Child Safety	–	1,406	–	–	8	1,414
Environmental Remediation	–	–	–	–	7	7
Pavement Life Recovery	–	89	–	–	3	92
Railroad Right of Way	–	–	–	–	–	–
Subdivision Participation	–	–	–	–	88	88
Total Transportation, Planning and Sustainability	–	1,495	1,519	–	106	3,120
Total transportation, planning and sustainability	$ –	1,495	1,522	–	(125)	2,892

(1) Expenditures include capital outlay of $442.

Expenditures (1)	Excess (Deficiency) Of Revenues Over Expenditures	Other Financing Sources (Uses)			Net Change in Fund Balances	Fund Balances at Beginning of Year	Fund Balances at End of Year
		Capital Leases	Transfers In	Transfers Out			
523	(52)	–	–	–	(52)	185	133
203	438	–	–	–	438	1,340	1,778
726	386	–	–	–	386	1,525	1,911
369	94	–	–	–	94	266	360
–	–	–	–	–	–	2	2
59	(51)	–	–	–	(51)	237	186
3	22	–	–	–	22	26	48
405	277	–	–	–	277	510	787
157	18	–	–	–	18	391	409
993	360	–	–	–	360	1,432	1,792
12	(6)	–	–	–	(6)	10	4
12	(6)	–	–	–	(6)	10	4
7,502	108	–	–	–	108	47	155
7,502	108	–	–	–	108	47	155
8,507	462	–	–	–	462	1,489	1,951
–	(231)	–	–	–	(231)	614	383
14	(11)	–	–	–	(11)	12	1
–	–	–	–	–	–	5	5
–	–	–	–	–	–	97	97
–	–	–	–	–	–	850	850
14	(242)	–	–	–	(242)	1,578	1,336
1,367	152	–	–	–	152	(152)	–
1,214	200	–	–	–	200	270	470
4	3	–	583	(632)	(46)	367	321
–	92	–	–	(140)	(48)	210	162
–	–	–	–	–	–	5	5
–	88	–	–	–	88	2,856	2,944
2,585	535	–	583	(772)	346	3,556	3,902
2,599	293	–	583	(772)	104	5,134	5,238

(Continued)

Special Revenue Funds - Other
Combining Statement of Revenues, Expenditures and Changes in Fund Balances
For the year ended September 30, 2003
(In thousands)

	Revenues					
	Gross Receipts Taxes	Fines, Forfeitures and Penalties	Charges for Services/ Goods	Contributions	Interest and Other	Total Revenues
Public health						
Health and Human Services:						
Disproportionate Share	$ –	–	–	–	–	–
Health and Human Services Travis County Reimbursed	–	–	4,879	–	–	4,879
Health Miscellaneous	–	–	–	21	5	26
Medicaid Administrative Claims	–	–	–	–	16	16
Total Health and Human Services	–	–	4,879	21	21	4,921
Other public health:						
Animal Shelter Building	–	–	–	–	–	–
Total other public health	–	–	–	–	–	–
Total public health	–	–	4,879	21	21	4,921
Public recreation and culture						
Austin Public Library:						
Austin History Center	–	–	–	3	–	3
Julia Cousins Trust	–	–	–	–	–	–
Miscellaneous Library	–	–	–	–	–	–
Special Library	–	–	–	83	–	83
Total Austin Public Library	–	–	–	86	–	86
Parks and Recreation:						
Adaptive Programs	–	–	34	–	–	34
Austin Creeks and Trails	–	–	–	–	–	–
Balcones Canyonlands	–	–	–	–	–	–
Friends of East Austin Youth	–	–	–	–	–	–
PARD Cultural Projects	–	–	–	–	2	2
PARD Miscellaneous	–	–	9	336	15	360
PARD Police Asset Forfeitures	–	–	–	–	1	1
Planting for the Future	–	–	–	203	–	203
Republic Square	–	–	–	1	–	1
Rifle Class	–	–	–	–	–	–
Senior Nutrition	–	–	–	–	–	–
Summer Musical	–	–	–	16	–	16
Teen Activity	–	–	–	163	–	163
Tennis League	–	–	–	1	–	1
Town Lake Beautification	–	–	–	229	–	229
Total Parks and Recreation	–	–	43	949	18	1,010
Total public recreation and culture	$ –	–	43	1,035	18	1,096

(Continued)

Expenditures (1)	Excess (Deficiency) Of Revenues Over Expenditures	Other Financing Sources (Uses)			Net Change in Fund Balances	Fund Balances at Beginning of Year	Fund Balances at End of Year
		Capital Leases	Transfers In	Transfers Out			
32	(32)	–	–	–	(32)	166	134
4,839	40	–	–	–	40	198	238
19	7	–	–	–	7	25	32
–	16	–	–	–	16	65	81
4,890	31	–	–	–	31	454	485
–	–	–	–	–	–	12	12
–	–	–	–	–	–	12	12
4,890	31	–	–	–	31	466	497
–	3	–	–	–	3	150	153
–	–	–	–	–	–	1	1
–	–	–	–	–	–	1	1
66	17	–	–	–	17	111	128
66	20	–	–	–	20	263	283
–	34	–	–	–	34	16	50
–	–	–	–	–	–	19	19
–	–	–	–	–	–	75	75
–	–	–	–	–	–	10	10
2,760	(2,758)	–	2,977	–	219	70	289
218	142	–	–	–	142	445	587
–	1	–	–	–	1	1	2
164	39	–	–	–	39	48	87
1	–	–	–	–	–	2	2
–	–	–	–	–	–	1	1
–	–	–	–	–	–	–	–
18	(2)	–	–	–	(2)	102	100
17	146	–	–	–	146	61	207
–	1	–	–	–	1	4	5
12	217	–	–	–	217	274	491
3,190	(2,180)	–	2,977	–	797	1,128	1,925
3,256	(2,160)	–	2,977	–	817	1,391	2,208

(Continued)

Special Revenue Funds - Other
Combining Statement of Revenues, Expenditures and Changes in Fund Balances
For the year ended September 30, 2003
(In thousands)

	Revenues					
	Gross Receipts Taxes	Fines, Forfeitures and Penalties	Charges for Services/ Goods	Contributions	Interest and Other	Total Revenues
Urban growth management						
Neighborhood Housing & Community Development:						
Housing Miscellaneous	$ –	–	–	–	1	1
Housing Trust Social Equity	–	–	–	–	20	20
Neighborhood Housing and Conservation	–	–	–	–	25	25
Total Neighborhood Housing & Community Development	–	–	–	–	46	46
Development Services and Watershed Protection:						
Austin Industrial Development Corporation (AIDC)	–	–	–	–	3	3
Austin Inner City Redevelopment Corporation	–	–	–	–	1	1
Energy Conservation Rebates and Incentives	–	–	6,001	–	–	6,001
Fee Waiver	–	–	–	–	1	1
Planning, Environmental Conservation Services	–	–	–	–	–	–
Public Improvement District	–	–	1,414	–	39	1,453
Urban Forest Replenishment	–	–	–	123	1	124
Total Development Services and Watershed Protection	–	–	7,415	123	45	7,583
Other:						
Barton Springs Conservation	–	–	–	–	5	5
Cable TV	–	–	647	–	2	649
Downtown Development	–	–	–	–	4	4
Hotel-Motel Occupancy Tax	25,955	30	–	–	–	25,985
Music Loan Program	–	–	–	–	5	5
One Texas Center	–	–	2,327	–	–	2,327
RMMA Reimbursement	–	–	–	1,238	5	1,243
Strategic Planning Investment	–	–	–	–	17	17
Sustainability	–	–	–	–	–	–
Tax Increment Finance	–	–	–	–	4	4
Tourism and Promotion	–	–	–	–	10	10
Vehicle Rental Tax	4,454	–	–	–	9	4,463
Wildland Conservation	–	37	–	–	31	68
Total other	30,409	67	2,974	1,238	92	34,780
Total urban growth management	30,409	67	10,389	1,361	183	42,409
2003 Total	$ 30,409	3,475	24,463	2,428	624	61,399

(Continued)

Expenditures (1)	Excess (Deficiency) Of Revenues Over Expenditures	Other Financing Sources (Uses)			Net Change in Fund Balances	Fund Balances at Beginning of Year	Fund Balances at End of Year
		Capital Leases	Transfers In	Transfers Out			
–	1	–	–	–	1	40	41
60	(40)	–	1,000	–	960	345	1,305
1,149	(1,124)	102	995	(265)	(292)	1,282	990
1,209	(1,163)	102	1,995	(265)	669	1,667	2,336
–	3	–	–	–	3	146	149
–	1	–	–	–	1	1	2
7,573	(1,572)	–	–	–	(1,572)	3,024	1,452
–	1	–	–	–	1	24	25
–	–	–	–	–	–	108	108
1,538	(85)	–	150	–	65	1,064	1,129
–	124	–	–	–	124	–	124
9,111	(1,528)	–	150	–	(1,378)	4,367	2,989
–	5	–	45	–	50	207	257
698	(49)	–	–	–	(49)	211	162
–	4	–	–	–	4	180	184
–	25,985	–	–	(25,508)	477	5,629	6,106
–	5	–	–	–	5	236	241
–	2,327	–	–	(690)	1,637	(93)	1,544
819	424	–	–	–	424	–	424
335	(318)	–	–	–	(318)	343	25
3,532	(3,532)	–	7,850	(4,369)	(51)	408	357
12	(8)	–	100	–	92	98	190
4,970	(4,960)	–	4,235	–	(725)	704	(21)
–	4,463	–	–	(4,473)	(10)	1,102	1,092
28	40	–	–	–	40	1,471	1,511
10,394	24,386	–	12,230	(35,040)	1,576	10,496	12,072
20,714	21,695	102	14,375	(35,305)	867	16,530	17,397
40,692	20,707	102	17,935	(36,077)	2,667	26,535	29,202

Special Revenue Funds - Other
Combining Schedule of Revenues, Expenditures and Transfers - Budget and Actual-Budget Basis
Year ended September 30, 2003
(In thousands)

City of Austin, Texas
Exhibit E-13

	Fund Balances at Beginning of Year	Revenues	Expenditures	Other Financing Sources (Uses) Transfer In	Other Financing Sources (Uses) Transfer Out	Excess of Sources Over Uses	Fund Balances at End of Year
General government							
Municipal Court:							
Municipal Court Building Security							
Actual-budget basis	$ 125	471	523	--	--	(52)	73
Budget	(144)	473	609	--	--	(136)	(280)
Variance	269	(2)	86	--	--	84	353
Municipal Court Technology							
Actual-budget basis	1,338	641	279	--	--	362	1,700
Budget	(4)	589	1,657	--	--	(1,068)	(1,072)
Variance	1,342	52	1,378	--	--	1,430	2,772
Public safety							
Police:							
Aviation Asset Forfeiture							
Actual-budget basis	227	8	60	--	--	(52)	175
Budget	(339)	63	113	--	--	(50)	(389)
Variance	566	(55)	53	--	--	(2)	564
Police Federal Seized Funds							
Actual-budget basis	431	682	409	--	--	273	704
Budget	(432)	138	400	--	--	(262)	(694)
Variance	863	544	(9)	--	--	535	1,398
Police Seized Money							
Actual-budget basis	381	175	174	--	--	1	382
Budget	(115)	120	175	--	--	(55)	(170)
Variance	496	55	1	--	--	56	552
Emergency Medical Services:							
EMS Travis County Reimbursed							
Actual-budget basis	$ 4	7,610	7,521	--	--	89	93
Budget	(171)	7,554	7,554	--	--	--	(171)
Variance	175	56	33	--	--	89	264

(Continued)

Special Revenue Funds - Other
Combining Schedule of Revenues, Expenditures and Transfers - Budget and Actual-Budget Basis
Year ended September 30, 2003
(In thousands)

City of Austin, Texas
Exhibit E-13

(Continued)

	Fund Balances at Beginning of Year	Revenues	Expenditures	Other Financing Sources (Uses) Transfer In	Other Financing Sources (Uses) Transfer Out	Excess of Sources Over Uses	Fund Balances at End of Year
Transportation, planning and sustainability							
Transportation, planning and sustainability							
Child Safety							
Actual-budget basis	$ 171	1,414	1,214	--	--	200	371
Budget	(396)	1,483	1,511	--	--	(28)	(424)
Variance	567	(69)	297	--	--	228	795
Environmental Remediation							
Actual-budget basis	361	7	2	583	634	(46)	315
Budget	110	20	50	583	634	(81)	29
Variance	251	(13)	48	--	--	35	286
Public health							
Health and Human Services Travis County Reimbursed							
Actual-budget basis	(382)	4,879	4,906	--	--	(27)	(409)
Budget	(1,863)	5,174	5,174	--	--	--	(1,863)
Variance	1,481	(295)	268	--	--	(27)	1,454
Public recreation and culture							
PARD Cultural Projects							
Actual-budget basis	(390)	2	2,612	2,977	--	367	(23)
Budget	(690)	20	2,623	3,039	--	436	(254)
Variance	300	(18)	11	(62)	--	(69)	231
PARD Police Asset Forfeiture							
Actual-budget basis	$ 2	--	--	--	--	--	2
Budget	(10)	--	2	--	--	(2)	(12)
Variance	12	--	2	--	--	2	14

(Continued)

Special Revenue Funds - Other
Combining Schedule of Revenues, Expenditures and Transfers - Budget and Actual-Budget Basis
Year ended September 30, 2003
(In thousands)

City of Austin, Texas
Exhibit E-13

(Continued)

	Fund Balances at Beginning of Year	Revenues	Expenditures	Other Financing Sources (Uses) Transfer In	Other Financing Sources (Uses) Transfer Out	Excess of Sources Over Uses	Fund Balances at End of Year
Urban growth management							
Neighborhood Planning and Zoning:							
Neighborhood Housing and Conservation							
Actual-budget basis	$ 986	25	1,222	995	--	(202)	784
Budget	(614)	33	1,715	1,020	--	(662)	(1,276)
Variance	1,600	(8)	493	(25)	--	460	2,060
Development Services and Watershed Protection:							
Energy Conservation Rebates and Incentives							
Actual-budget basis	1,073	6,001	7,847	--	--	(1,846)	(773)
Budget	404	8,224	9,424	--	--	(1,200)	(796)
Variance	669	(2,223)	1,577	--	--	(646)	23
Public Improvement District							
Actual-budget basis	312	1,453	1,573	150	--	30	342
Budget	475	1,523	1,573	150	--	100	575
Variance	(163)	(70)	--	--	--	(70)	(233)
Other							
Hotel-Motel Occupancy Tax							
Actual-budget basis	--	25,508	--	--	25,508	--	--
Budget	--	26,047	--	--	26,047	--	--
Variance	--	(539)	--	--	539	--	--
One Texas Center							
Actual-budget basis	$ (93)	2,327	--	--	690	1,637	1,544
Budget	(512)	1,817	--	--	690	1,127	615
Variance	419	510	--	--	--	510	929

(Continued)

	Fund Balances at Beginning of Year	Revenues	Expenditures	Other Financing Sources (Uses) Transfer In	Other Financing Sources (Uses) Transfer Out	Excess of Sources Over Uses	Fund Balances at End of Year
Sustainability							
Actual-budget basis	$ 80	--	3,572	7,850	4,369	(91)	(11)
Budget	--	--	3,694	8,063	4,369	--	--
Variance	80	--	122	(213)	--	(91)	(11)
Tourism and Promotion							
Actual-budget basis	720	10	4,970	4,235	--	(725)	(5)
Budget	(12)	50	4,970	4,322	--	(598)	(610)
Variance	732	(40)	--	(87)	--	(127)	605
Vehicle Rental Tax							
Actual-budget basis	(2,189)	4,472	--	--	4,473	(1)	(2,190)
Budget	(5,107)	5,000	--	--	5,000	--	(5,107)
Variance	2,918	(528)	--	--	527	(1)	2,917
Wildland Conservation							
Actual-budget basis	1,434	40	44	--	--	(4)	1,430
Budget	(469)	--	--	--	--	--	(469)
Variance	1,903	40	(44)	--	--	(4)	1,899
Total							
Actual-budget basis	$ 4,591	55,725	36,928	16,790	35,674	(87)	4,504
Budget	(9,889)	58,328	41,244	17,177	36,740	(2,479)	(12,368)
Variance	14,480	(2,603)	4,316	(387)	1,066	2,392	16,872

CITY OF AUSTIN
FOUNDED 1839

DEBT SERVICE FUNDS

Debt service funds are used to account for the accumulation of resources for, and the payment of, general long-term debt. The two debt service funds are as follows:

The General Obligation Debt Service Fund – used for payments of principal, interest and related costs of general obligation and other tax-supported debt;

The Section 108 Loans Fund - used to account for HUD loans for construction costs.

CITY OF AUSTIN
FOUNDED 1839

Debt Service Funds
Combining Balance Sheet
September 30, 2003
(In thousands)

City of Austin, Texas
Exhibit E-14

	General Obligation	HUD Section 108 Loans	2003 Total
ASSETS			
Pooled investments and cash	$ 269	–	269
Investments, at fair value	13,749	–	13,749
Property taxes receivable	4,302	–	4,302
Less allowance for uncollectible taxes	(697)	–	(697)
Net property taxes receivable	3,605	–	3,605
Net accounts receivable	2	–	2
Due from other funds	6	–	6
Advances to other funds	4,677	–	4,677
Prepaid expenses	9	–	9
Total assets	22,317	–	22,317
LIABILITIES AND FUND BALANCES			
Deferred revenue	3,458	–	3,458
Advances from other funds	248	–	248
Deposits and other liabilities	1,300	–	1,300
Total liabilities	5,006	–	5,006
Fund balances			
Reserved:			
Debt service	17,311	–	17,311
Total fund balances	17,311	–	17,311
Total liabilities and fund balances	$ 22,317	–	22,317

Debt Service Funds
Combining Statement of Revenues, Expenditures and Changes in Fund Balances
For the year ended September 30, 2003
(In thousands)

City of Austin, Texas
Exhibit E-15

	General Obligation	HUD Section 108 Loans	2003 Total
REVENUES			
Property taxes	$ 82,195	--	82,195
Fines, forfeitures and penalties	525	--	525
Interest and other	3,731	1,519	5,250
Total revenues	86,451	1,519	87,970
EXPENDITURES			
Debt service:			
Principal	48,785	555	49,340
Interest	37,565	964	38,529
Fees and commissions	8	--	8
Total expenditures	86,358	1,519	87,877
Excess (deficiency) of revenues over expenditures	93	--	93
OTHER FINANCING SOURCES (USES)			
Issuance of refunding bonds	62,514	--	62,514
Payment to escrow agent	(62,514)	--	(62,514)
Transfers in	767	--	767
Total other financing sources (uses)	767	--	767
Net change in fund balances	860	--	860
Fund balances at beginning of year	16,451	--	16,451
Fund balances at end of year	$ 17,311	--	17,311

Debt Service Funds
Combining Schedule of Revenues, Expenditures and Changes in Fund Balances - Budget and Actual-Budget Basis
For the year ended September 30, 2003
(In thousands)

	General Obligation			HUD Section 108 Loans			
	Actual-Budget Basis	Budget	Variance-Positive (Negative)	Actual-Budget Basis	Budget	Variance-Positive (Negative)	2003 Actual-Budget Basis Total
REVENUES							
General property taxes	$ 82,720	83,270	(550)	--	--	--	82,720
Interest	719	995	(276)	--	--	--	719
Other revenue	3,698	3,680	18	1,519	1,301	218	5,217
Total revenues	87,137	87,945	(808)	1,519	1,301	218	88,656
EXPENDITURES							
Principal retirement	57,844	58,519	675	555	515	(40)	58,399
Interest and other	41,251	44,119	2,868	964	777	(187)	42,215
Fees and commissions	8	15	7	--	9	9	8
Total expenditures	99,103	102,653	3,550	1,519	1,301	(218)	100,622
Excess (deficiency) of revenues over expenditures	(11,966)	(14,708)	2,742	--	--	--	(11,966)
OTHER FINANCING SOURCES (USES)							
Issuance of refunding bonds	62,514	--	62,514	--	--	--	62,514
Payment to escrow agent	(62,514)	--	(62,514)	--	--	--	(62,514)
Transfers in	10,946	11,277	(331)	--	--	--	10,946
Total other financing sources (uses)	10,946	11,277	(331)	--	--	--	10,946
Excess (deficiency) of revenues and other sources over expenditures and other uses	(1,020)	(3,431)	2,411	--	--	--	(1,020)
Fund balances at beginning of year	13,832	13,696	136	--	--	--	13,832
Fund balances at end of year	$ 12,812	10,265	2,547	--	--	--	12,812

CAPITAL PROJECTS FUNDS

Capital projects funds are used to account for financial resources to be used for the acquisition or construction of major capital facilities other than those financed by proprietary funds and trust funds. There are eight major groups of funds that account for the activities related to the capital improvement projects:

Prior to 1984: Funds authorized prior to 1981;

Funds authorized August 29, 1981, for street and drainage, fire stations, traffic signals and emergency medical service projects;

Funds authorized September 11, 1982, for various purposes;

Funds authorized October 22, 1983, for Jollyville Road Improvements;

1984: Funds authorized September 8, 1984, for various purposes;

1985: Funds authorized January 19, 1985, for cultural arts;

Funds authorized July 26, 1985, for parks and recreation;

Funds authorized September 26, 1985, for art in public places;

Funds authorized December 14, 1985, for various purposes;

1987: Funds authorized September 3, 1987, for street improvements;

1992: Funds authorized August 10, 1992, for various purposes;

1997: Funds authorized May 3, 1997, for radio trunking;

1998: Funds authorized November 3, 1998, for various purposes;

2000: Funds authorized November 7, 2000, for street improvements and land acquisition; and

Other: Other funds established for various purposes.

CITY OF AUSTIN
FOUNDED 1839

Capital Projects Funds
Balance Sheet
September 30, 2003
(In thousands)

City of Austin, Texas
Exhibit E-17

	2003
ASSETS	
Pooled investments and cash	$ 119,255
Accounts and other taxes receivable	82,547
Less allowance for doubtful accounts	(139)
Net accounts receivable	82,408
Due from other funds	22,416
Other assets	413
Total assets	224,492
LIABILITIES AND FUND BALANCES	
Accounts payable	11,649
Due to other funds	22,416
Deposits and other liabilities	1,319
Total liabilities	35,384
Fund balances	
Reserved:	
Encumbrances	84,666
Unreserved, undesignated:	
Capital projects	104,442
Total fund balances	189,108
Total liabilities and fund balances	$ 224,492

Capital Projects Funds
Statement of Revenues, Expenditures and Changes in Fund Balances
For the year ended September 30, 2003
(In thousands)

City of Austin, Texas
Exhibit E-18

	2003
REVENUES	
Intergovernmental	$ 14,819
Property owners' participation and contributions	10,935
Interest and other	3,412
Total revenues	29,166
EXPENDITURES	
Capital outlay	155,517
Total expenditures	155,517
Excess (deficiency) of revenues over expenditures	(126,351)
OTHER FINANCING SOURCES (USES)	
Issuance of tax supported debt	70,323
Transfers in	18,139
Transfers out	(4,970)
Total other financing sources (uses)	83,492
Net change in fund balances	(42,859)
Fund balances at beginning of year	231,967
Fund balances at end of year	$ 189,108

Capital Projects Funds
Combining Balance Sheet
September 30, 2003
(In thousands)

	Assets						
	Pooled Investments and Cash	Accounts Receivable	Allowance for Doubtful Accounts	Net Accounts Receivable	Due from Other Funds	Other Assets	Total Assets
Funds Authorized *Prior to* 1981							
Parks and recreation	$ 177	–	–	–	–	–	177
Police and courts	2	–	–	–	–	–	2
Street improvements	57	–	–	–	–	–	57
Library	7	–	–	–	–	–	7
Health centers	–	–	–	–	–	–	–
	243	–	–	–	–	–	243
Funds Authorized August 29, 1981							
Street and drainage	–	–	–	–	3	–	3
Fire stations	–	–	–	–	24	–	24
EMS buildings	–	765	–	765	–	–	765
	–	765	–	765	27	–	792
Funds Authorized September 11, 1982							
Flood prevention	106	–	–	–	–	–	106
Parks–various	173	–	–	–	–	–	173
Environmental resources	2	–	–	–	–	–	2
Fire/EMS building	43	–	–	–	–	–	43
	324	–	–	–	–	–	324
Funds Authorized October 22, 1983							
Jollyville road improvements	–	–	–	–	27	–	27
Energy improvements - city facilities	–	–	–	–	–	–	–
	–	–	–	–	27	–	27
Total Prior to 1984	567	765	–	765	54	–	1,386
Funds Authorized September 8, 1984							
PARD pools	5	–	–	–	–	–	5
Parkland acquisition	2	–	–	–	–	–	2
Parks/Old Bakery	–	–	–	–	–	–	–
Drainage and flood improvements	4,650	–	–	–	–	–	4,650
Street improvements	2,130	331	–	331	193	–	2,654
Fire improvements	11	–	–	–	–	–	11
Libraries	1	–	–	–	–	–	1
Police facilities	–	–	–	–	–	–	–
Traffic signals	4	–	–	–	–	–	4
EMS/Fire facility	3	–	–	–	–	–	3
	$ 6,806	331	–	331	193	–	7,330

Liabilities				Fund Balances			
Accounts Payable	Due to Other Funds	Other Liabilities	Total Liabilities	Reserved for Encumbrances	Unreserved, Undesignated (Deficit)	Total Fund Balances	Total Liabilities and Fund Balances
–	–	–	–	–	177	177	177
–	–	–	–	–	2	2	2
–	–	–	–	–	57	57	57
–	–	–	–	–	7	7	7
–	–	–	–	–	–	–	–
–	–	–	–	–	243	243	243
–	–	–	–	–	3	3	3
–	–	–	–	–	24	24	24
–	481	–	481	10	274	284	765
–	481	–	481	10	301	311	792
–	–	–	–	–	106	106	106
–	–	–	–	1	172	173	173
–	–	–	–	–	2	2	2
–	–	–	–	–	43	43	43
–	–	–	–	1	323	324	324
–	–	–	–	–	27	27	27
–	82	–	82	5	(87)	(82)	–
–	82	–	82	5	(60)	(55)	27
–	563	–	563	16	807	823	1,386
–	–	–	–	–	5	5	5
–	–	–	–	–	2	2	2
–	179	–	179	27	(206)	(179)	–
–	–	–	–	130	4,520	4,650	4,650
32	–	–	32	450	2,172	2,622	2,654
–	–	–	–	–	11	11	11
–	–	–	–	–	1	1	1
–	14	–	14	–	(14)	(14)	–
–	–	–	–	–	4	4	4
–	–	–	–	–	3	3	3
32	193	–	225	607	6,498	7,105	7,330

(Continued)

Capital Projects Funds
Combining Balance Sheet
September 30, 2003
(In thousands)

	Assets						
	Pooled Investments and Cash	Accounts Receivable	Allowance for Doubtful Accounts	Net Accounts Receivable	Due from Other Funds	Other Assets	Total Assets
Funds Authorized January 19, 1985							
Cultural arts	$ 1,364	–	–	–	–	413	1,777
Downtown art museum	168	–	–	–	–	–	168
	1,532	–	–	–	–	413	1,945
Funds Authorized July 26, 1985							
Neighborhood park and recreation	4,720	–	–	–	–	–	4,720
Funds Authorized September 26, 1985							
Art in public places	13	–	–	–	–	–	13
Funds Authorized December 14, 1985							
Senior activity center	3	–	–	–	–	–	3
South Austin parkland	11	–	–	–	–	–	11
Parks Oak Hill	2	–	–	–	–	–	2
	16	–	–	–	–	–	16
Total Funds Authorized in 1985	6,281	–	–	–	–	413	6,694
Funds Authorized September 3, 1987							
Street resurfacing	145	140	(139)	1	–	–	146
Funds Authorized August 10, 1992							
EMS facility	49	–	–	–	–	–	49
Fire stations	12	–	–	–	–	–	12
Police substations	37	–	–	–	104	–	141
Asbestos abatement/ADA compliance/ East Austin health clinic	1,549	–	–	–	–	–	1,549
Erosion & flood control	5,077	–	–	–	–	–	5,077
Street & traffic signals	252	–	–	–	–	–	252
Neighborhood sidewalks	62	–	–	–	–	–	62
Parks and recreation facilities	686	–	–	–	–	–	686
Libraries	42	–	–	–	–	–	42
Balcones Canyonlands Conservation Plan	3	–	–	–	–	–	3
Barton Creek greenway	325	–	–	–	–	–	325
	8,094	–	–	–	104	–	8,198
Funds Authorized May 3, 1997							
Radio Trunking	1,203	1,633	–	1,633	–	–	2,836
	$ 1,203	1,633	–	1,633	–	–	2,836

(Continued)

Liabilities				Fund Balances			
Accounts Payable	Due to Other Funds	Other Liabilities	Total Liabilities	Reserved for Encumbrances	Unreserved, Undesignated (Deficit)	Total Fund Balances	Total Liabilities and Fund Balances
–	–	–	–	1	1,776	1,777	1,777
–	–	–	–	–	168	168	168
–	–	–	–	1	1,944	1,945	1,945
25	–	–	25	53	4,642	4,695	4,720
–	–	–	–	–	13	13	13
–	–	–	–	–	3	3	3
–	–	–	–	–	11	11	11
–	–	–	–	–	2	2	2
–	–	–	–	–	16	16	16
25	–	–	25	54	6,615	6,669	6,694
–	–	–	–	–	146	146	146
–	–	–	–	–	49	49	49
–	–	–	–	2	10	12	12
–	–	–	–	84	57	141	141
23	–	–	23	130	1,396	1,526	1,549
329	–	–	329	1,349	3,399	4,748	5,077
–	–	–	–	–	252	252	252
1	–	–	1	30	31	61	62
8	–	–	8	32	646	678	686
–	–	–	–	24	18	42	42
–	–	–	–	–	3	3	3
–	–	–	–	–	325	325	325
361	–	–	361	1,651	6,186	7,837	8,198
6	–	–	6	4,364	(1,534)	2,830	2,836
6	–	–	6	4,364	(1,534)	2,830	2,836

(Continued)

Capital Projects Funds
Combining Balance Sheet
September 30, 2003
(In thousands)

	Assets						
	Pooled Investments and Cash	Accounts Receivable	Allowance for Doubtful Accounts	Net Accounts Receivable	Due from Other Funds	Other Assets	Total Assets
Funds Authorized November 3, 1998							
Cultural arts and land	$ 17,633	–	–	–	–	–	17,633
Drainage and flood control	2,169	–	–	–	–	–	2,169
Traffic signals	23,952	20,978	–	20,978	–	–	44,930
Public safety facilities	3,140	8,505	–	8,505	–	–	11,645
Parks and recreation facilities	878	14,473	–	14,473	–	–	15,351
	47,772	43,956	–	43,956	–	–	91,728
Funds Authorized 2000							
Transportation Mobility Improvement	–	15,000	–	15,000	–	–	15,000
Open Spaces	–	3,400	–	3,400	4,408	–	7,808
	–	18,400	–	18,400	4,408	–	22,808
Other funds							
Planning & development improvements	750	–	–	–	–	–	750
TPSD general improvements	9,343	128	–	128	–	–	9,471
Parks-1992	–	–	–	–	–	–	–
Library automation system	870	–	–	–	–	–	870
Fire/EMS/NW Austin MUD #1	619	–	–	–	–	–	619
General government projects	14,453	–	–	–	1,419	–	15,872
Health projects	1,145	–	–	–	–	–	1,145
Build Austin	–	79	–	79	–	–	79
CMTA Mobility	5,625	3,762	–	3,762	–	–	9,387
Forsythia Drive	3	–	–	–	–	–	3
Central City Entertainment Center	10	–	–	–	–	–	10
Park improvements	4,275	–	–	–	–	–	4,275
Police and courts	146	–	–	–	–	–	146
Health centers	–	–	–	–	–	–	–
Neighborhood centers	8	–	–	–	–	–	8
Loan star improvements	331	–	–	–	–	–	331
Fire - general	5,317	1,145	–	1,145	–	–	6,462
Capital reserve	–	11,540	–	11,540	–	–	11,540
Public Works	3	–	–	–	–	–	3
One Texas Center	187	–	–	–	–	–	187
Watershed Protection	121	650	–	650	151	–	922
Great Streets	1,077	–	–	–	–	–	1,077
City Hall, plaza, parking garage	962	–	–	–	15,578	–	16,540
Conservation Land	–	18	–	18	–	–	18
Colony Park	1,896	–	–	–	–	–	1,896
Economic Development	30	–	–	–	509	–	539
Interest income fund	1,216	–	–	–	–	–	1,216
Total other funds	48,387	17,322	–	17,322	17,657	–	83,366
2003 Totals	$ 119,255	82,547	(139)	82,408	22,416	413	224,492

Liabilities				Fund Balances			
Accounts Payable	Due to Other Funds	Other Liabilities	Total Liabilities	Reserved for Encumbrances	Unreserved, Undesignated (Deficit)	Total Fund Balances	Total Liabilities and Fund Balances
732	–	–	732	5,672	11,229	16,901	17,633
178	–	–	178	983	1,008	1,991	2,169
3,232	–	–	3,232	18,494	23,204	41,698	44,930
2,024	–	–	2,024	4,700	4,921	9,621	11,645
426	–	–	426	1,919	13,006	14,925	15,351
6,592	–	–	6,592	31,768	53,368	85,136	91,728
–	15,082	–	15,082	–	(82)	(82)	15,000
3	–	–	3	–	7,805	7,805	7,808
3	15,082	–	15,085	–	7,723	7,723	22,808
–	–	–	–	–	750	750	750
204	–	–	204	1,856	7,411	9,267	9,471
26	147	–	173	37	(210)	(173)	–
–	–	–	–	64	806	870	870
–	–	–	–	–	619	619	619
31	–	412	443	1,423	14,006	15,429	15,872
649	–	–	649	2,002	(1,506)	496	1,145
–	104	–	104	44	(69)	(25)	79
960	–	–	960	9,889	(1,462)	8,427	9,387
–	–	–	–	–	3	3	3
–	–	–	–	–	10	10	10
140	–	–	140	298	3,837	4,135	4,275
–	–	–	–	11	135	146	146
–	–	–	–	–	–	–	–
–	–	–	–	–	8	8	8
–	–	–	–	14	317	331	331
19	–	–	19	227	6,216	6,443	6,462
1,743	6,323	–	8,066	5,248	(1,774)	3,474	11,540
24	–	–	24	225	(246)	(21)	3
–	–	–	–	–	187	187	187
210	–	–	210	85	627	712	922
–	–	–	–	–	1,077	1,077	1,077
624	–	250	874	24,783	(9,117)	15,666	16,540
–	4	15	19	–	(1)	(1)	18
–	–	–	–	–	1,896	1,896	1,896
–	–	–	–	–	539	539	539
–	–	642	642	–	574	574	1,216
4,630	6,578	1,319	12,527	46,206	24,633	70,839	83,366
11,649	22,416	1,319	35,384	84,666	104,442	189,108	224,492

Capital Projects Funds
Combining Statement of Revenues, Expenditures and
Changes in Fund Balances
September 30, 2003
(In thousands)

	Revenues				Expenditures
	Inter-governmental Revenues	Property Owners' Participation and Contributions	Interest and Other	Total Revenues	Capital Outlay
Funds Authorized Prior to 1981					
Parks and recreation	$ –	–	–	–	–
Police and courts	–	–	–	–	–
Street improvements	–	–	–	–	–
Library	–	–	–	–	–
Health centers	–	–	–	–	9
	–	–	–	–	9
Funds Authorized August 29, 1981					
Street and drainage	–	–	–	–	–
Fire stations	–	–	–	–	–
EMS buildings	–	–	–	–	784
	–	–	–	–	784
Funds Authorized September 11, 1982					
Flood prevention	–	–	–	–	22
Parks–various	–	–	–	–	9
Environmental resources	–	–	–	–	–
Fire/EMS building	–	–	–	–	–
	–	–	–	–	31
Funds Authorized October 22, 1983					
Jollyville road improvements	–	–	–	–	–
Energy improvements - city facilities	–	–	–	–	–
	–	–	–	–	–
Total Prior to 1984	–	–	–	–	824
Funds Authorized September 8, 1984					
PARD pools	–	–	–	–	–
Parkland acquisition	–	–	–	–	–
Parks/Old Bakery	–	–	–	–	34
Drainage and flood improvements	–	–	–	–	406
Street improvements	–	–	–	–	1,067
Fire improvements	–	–	–	–	–
Libraries	–	–	–	–	–
Police facilities	–	–	–	–	–
Traffic signals	–	–	–	–	–
EMS/Fire facility	–	–	–	–	–
	$ –	–	–	–	1,507

Excess (Deficiency) of Revenues Over Expenditures	Other Financing Sources (Uses)				Net Change in Fund Balances	Fund Balances at Beginning of Year	Fund Balances at End of Year
	Issuance of Tax Supported Debt	Transfers In	Transfers Out	Total Other Financing Sources(Uses)			
--	--	--	--	--	--	177	177
--	--	--	--	--	--	2	2
--	--	--	--	--	--	57	57
--	--	--	--	--	--	7	7
(9)	--	--	--	--	(9)	9	--
(9)	--	--	--	--	(9)	252	243
--	--	--	--	--	--	3	3
--	--	--	--	--	--	24	24
(784)	765	--	--	765	(19)	303	284
(784)	765	--	--	765	(19)	330	311
(22)	--	--	--	--	(22)	128	106
(9)	--	--	--	--	(9)	182	173
--	--	--	--	--	--	2	2
--	--	--	--	--	--	43	43
(31)	--	--	--	--	(31)	355	324
--	--	--	--	--	--	27	27
--	--	--	--	--	--	(82)	(82)
--	--	--	--	--	--	(55)	(55)
(824)	765	--	--	765	(59)	882	823
--	--	--	--	--	--	5	5
--	--	--	--	--	--	2	2
(34)	--	--	--	--	(34)	(145)	(179)
(406)	--	--	--	--	(406)	5,056	4,650
(1,067)	--	--	--	--	(1,067)	3,689	2,622
--	--	--	--	--	--	11	11
--	--	--	--	--	--	1	1
--	--	--	--	--	--	(14)	(14)
--	--	--	--	--	--	4	4
--	--	--	--	--	--	3	3
(1,507)	--	--	--	--	(1,507)	8,612	7,105

(Continued)

Capital Projects Funds
Combining Statement of Revenues, Expenditures and
Changes in Fund Balances
September 30, 2003
(In thousands)

	Revenues				Expenditures
	Inter-governmental Revenues	Property Owners' Participation and Contributions	Interest and Other	Total Revenues	Capital Outlay
Funds Authorized January 19, 1985					
Cultural arts	$ –	–	68	68	11
Downtown art museum	–	–	–	–	–
	–	–	68	68	11
Funds Authorized July 26, 1985					
Neighborhood park and recreation	–	581	53	634	260
Funds Authorized September 26, 1985					
Art in public places	–	–	–	–	2
Funds Authorized December 14, 1985					
Senior activity center	–	–	–	–	–
South Austin parkland	–	–	–	–	–
Parks Oak Hill	–	–	–	–	–
	–	–	–	–	–
Total Funds Authorized in 1985	–	581	121	702	273
Funds Authorized September 3, 1987					
Street resurfacing	33	3	4	40	3
Funds Authorized August 10, 1992					
EMS facility	–	–	–	–	–
Fire stations	–	–	–	–	–
Police substations	–	–	–	–	–
Asbestos abatement/ADA compliance/ East Austin health clinic	–	–	–	–	1,090
Erosion & flood control	–	–	–	–	882
Street & traffic signals	–	–	–	–	1
Neighborhood sidewalks	–	–	–	–	14
Parks and recreation facilities	49	–	–	49	147
Libraries	–	–	–	–	2
Balcones Canyonlands Conservation Plan	–	–	–	–	2
Barton Creek greenway	–	–	–	–	–
	49	–	–	49	2,138
Funds Authorized May 3, 1997					
Radio Trunking	–	3,043	–	3,043	19,553
	$ –	3,043	–	3,043	19,553

(Continued)

Excess (Deficiency) of Revenues Over Expenditures	Other Financing Sources (Uses)				Net Change in Fund Balances	Fund Balances at Beginning of Year	Fund Balances at End of Year
	Issuance of Tax Supported Debt	Transfers In	Transfers Out	Total Other Financing Sources(Uses)			
57	–	–	(68)	(68)	(11)	1,788	1,777
–	–	–	–	–	–	168	168
57	–	–	(68)	(68)	(11)	1,956	1,945
374	–	736	(736)	–	374	4,321	4,695
(2)	–	–	–	–	(2)	15	13
–	–	–	–	–	–	3	3
–	–	–	–	–	–	11	11
–	–	–	–	–	–	2	2
–	–	–	–	–	–	16	16
429	–	736	(804)	(68)	361	6,308	6,669
37	–	–	–	–	37	109	146
–	–	–	–	–	–	49	49
–	–	–	–	–	–	12	12
–	–	–	–	–	–	141	141
(1,090)	–	–	–	–	(1,090)	2,616	1,526
(882)	–	–	–	–	(882)	5,630	4,748
(1)	–	–	–	–	(1)	253	252
(14)	–	–	–	–	(14)	75	61
(98)	–	–	–	–	(98)	776	678
(2)	–	–	–	–	(2)	44	42
(2)	–	–	–	–	(2)	5	3
–	–	–	–	–	–	325	325
(2,089)	–	–	–	–	(2,089)	9,926	7,837
(16,510)	–	–	–	–	(16,510)	19,340	2,830
(16,510)	–	–	–	–	(16,510)	19,340	2,830

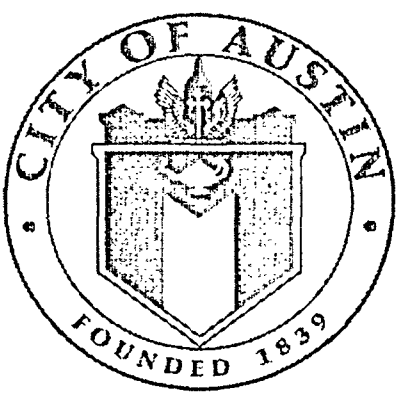
(Continued)

Capital Projects Funds
Combining Statement of Revenues, Expenditures and
Changes in Fund Balances
September 30, 2003
(In thousands)

	Revenues				Expenditures
	Inter-governmental Revenues	Property Owners' Participation and Contributions	Interest and Other	Total Revenues	Capital Outlay
Funds Authorized November 3, 1998					
Cultural arts and land	$ –	–	–	–	10,509
Drainage and flood control	–	–	–	–	2,555
Traffic signals	–	–	–	–	22,199
Public safety facilities	–	–	–	–	22,886
Parks and recreation facilities	–	–	–	–	12,702
	–	–	–	–	70,851
Funds Authorized 2000					
Transportation Mobility Improvement	–	–	–	–	37
Open Spaces	–	–	–	–	3,105
	–	–	–	–	3,142
Other funds					
Planning & development improvements	–	–	–	–	–
TPSD general improvements	–	–	159	159	2,974
Parks-1992	–	–	–	–	158
Library automation system	–	15	9	24	120
Fire/EMS/NW Austin MUD #1	–	–	12	12	–
General government projects	–	–	–	–	–
Health projects	3,054	–	–	3,054	4,802
Build Austin	150	–	–	150	148
CMTA Mobility	10,470	–	263	10,733	20,824
Forsythia Drive	–	–	–	–	–
Central City Entertainment Center	–	–	–	–	18
Park improvements	–	9	–	9	1,383
Police and courts	–	–	–	–	11
Health centers	–	–	–	–	17
Neighborhood centers	–	–	–	–	–
Loan star improvements	–	–	–	–	–
Fire - general	–	–	–	–	2,719
Capital reserve	–	7,284	–	7,284	13,617
Public Works	1,063	–	–	1,063	1,034
One Texas Center	–	–	–	–	–
Watershed Protection	–	–	–	–	1,505
Great Streets	–	–	3	3	–
City Hall, plaza, parking garage	–	–	–	–	5,779
Conservation Land	–	–	1	1	–
Colony Park	–	–	–	–	2,117
Economic Development	–	–	–	–	–
Interest income fund	–	–	2,840	2,840	–
Total other funds	14,737	7,308	3,287	25,332	57,226
2003 Totals	$ 14,819	10,935	3,412	29,166	155,517

(Continued)

Excess (Deficiency) of Revenues Over Expenditures	Other Financing Sources (Uses)				Net Change in Fund Balances	Fund Balances at Beginning of Year	Fund Balances at End of Year
	Issuance of Tax Supported Debt	Transfers In	Transfers Out	Total Other Financing Sources(Uses)			
(10,509)	–	–	–	–	(10,509)	27,410	16,901
(2,555)	–	–	–	–	(2,555)	4,546	1,991
(22,199)	20,915	–	–	20,915	(1,284)	42,982	41,698
(22,886)	8,505	–	–	8,505	(14,381)	24,002	9,621
(12,702)	14,473	–	–	14,473	1,771	13,154	14,925
(70,851)	43,893	–	–	43,893	(26,958)	112,094	85,136
(37)	15,000	–	–	15,000	14,963	(15,045)	(82)
(3,105)	3,400	–	–	3,400	295	7,510	7,805
(3,142)	18,400	–	–	18,400	15,258	(7,535)	7,723
–	–	–	–	–	–	750	750
(2,815)	–	1,545	–	1,545	(1,270)	10,537	9,267
(158)	–	–	–	–	(158)	(15)	(173)
(96)	–	578	–	578	482	388	870
12	–	–	–	–	12	607	619
–	–	3,854	–	3,854	3,854	11,575	15,429
(1,748)	–	269	–	269	(1,479)	1,975	496
2	–	–	–	–	2	(27)	(25)
(10,091)	–	–	–	–	(10,091)	18,518	8,427
–	–	–	–	–	–	3	3
(18)	–	–	–	–	(18)	28	10
(1,374)	–	1,825	–	1,825	451	3,684	4,135
(11)	–	–	–	–	(11)	157	146
(17)	–	–	–	–	(17)	17	–
–	–	–	–	–	–	8	8
–	–	–	–	–	–	331	331
(2,719)	1,145	2,500	–	3,645	926	5,517	6,443
(6,333)	6,038	–	(1,925)	4,113	(2,220)	5,694	3,474
29	–	–	–	–	29	(50)	(21)
–	–	–	–	–	–	187	187
(1,505)	650	600	–	1,250	(255)	967	712
3	–	399	(490)	(91)	(88)	1,165	1,077
(5,779)	(568)	2,400	–	1,832	(3,947)	19,613	15,666
1	–	–	–	–	1	(2)	(1)
(2,117)	–	3,365	–	3,365	1,248	648	1,896
–	–	–	–	–	–	539	539
2,840	–	68	(1,751)	(1,683)	1,157	(583)	574
(31,894)	7,265	17,403	(4,166)	20,502	(11,392)	82,231	70,839
(126,351)	70,323	18,139	(4,970)	83,492	(42,859)	231,967	189,108


CITY OF AUSTIN
FOUNDED 1839

PERMANENT FUNDS

Permanent funds are used to account for resources that are legally restricted to the extent that only earnings, and not principal, may be used for purposes that support the reporting government's programs – this is, for the benefit of the government or its citizenry.

3M Maintenance Endowment – Purpose is to account for 3M Mitigation Land Endowment.

Ellis Library Trust – Purpose is to account for principal and interest income earned on the principal from the Ellis estate. This income is used for purchasing books on the subject of mental health.

Perpetual Care – Revenues to be used for maintenance and care of cemeteries.

CITY OF AUSTIN
FOUNDED 1839

Permanent Funds
Combining Balance Sheet
September 30, 2003
(In thousands)

City of Austin, Texas
Exhibit E-21

	3M Maintenance Endowment	Ellis Library Trust	Perpetual Care	2003 Total
ASSETS				
Pooled investments and cash	$ 50	23	1,280	1,353
Total assets	50	23	1,280	1,353
LIABILITIES AND FUND BALANCES				
Fund balances				
Reserved:				
Permanent funds	50	9	981	1,040
Unreserved, undesignated:				
Permanent funds	–	14	299	313
Total fund balances	50	23	1,280	1,353
Total liabilities and fund balances	$ 50	23	1,280	1,353

Permanent Funds **City of Austin, Texas**
Combining Statement of Revenues, Expenditures and Changes in Fund Balances **Exhibit E-22**
For the year ended September 30, 2003
(In thousands)

	3M Maintenance Endowment	Ellis Library Trust	Perpetual Care	2003 Total
REVENUES				
Property owners' participation and contributions	$ --	--	2	2
Interest and other	--	1	26	27
Total revenues	--	1	28	29
Net change in fund balances	--	1	28	29
Fund balances at beginning of year	50	22	1,252	1,324
Fund balances at end of year	$ 50	23	1,280	1,353

CITY OF AUSTIN
FOUNDED 1839

NONMAJOR ENTERPRISE FUNDS

Enterprise funds account for the acquisition, operations and maintenance of the City's facilities and services that are entirely or predominantly supported by user charges or those for which the City has decided that periodic determination of the revenues earned, expenses incurred, and/or net income is appropriate for capital maintenance, public policy, management control, accountability or other purposes. All activities necessary to provide services are accounted for in these funds, including, but not limited to, administration, operations, and maintenance. The nonmajor enterprise funds are as follows:

The Austin Women's Hospital
The Convention Center Fund;
The Drainage Fund;
The Golf Fund;
The Hospital Fund;
The Parks and Recreation Fund;
The Primary Care Fund;
The Solid Waste Services Fund; and
The Transportation Fund

CITY OF AUSTIN
FOUNDED 1839

Nonmajor Enterprise Funds
Combining Statement of Net Assets
September 30, 2003
(In thousands)

	Austin Women's Hospital	Convention Center	Drainage	Golf	Hospital
ASSETS					
Current assets:					
Cash	$ --	7	3	1	--
Pooled investments and cash	89	11,572	4,325	241	73
Pooled investments and cash - designated	--	12,580	--	--	--
Pooled investments and cash - restricted	--	28,920	27,960	946	--
Total pooled investments and cash	89	53,072	32,285	1,187	73
Investments, at fair value - designated	--	297	--	--	--
Investments, at fair value - restricted	--	14,011	--	--	--
Working capital advances	--	124	--	--	--
Accounts receivable	--	478	2,627	--	3,307
Less allowance for doubtful accounts	--	(4)	(114)	--	(3,094)
Net accounts receivable	--	474	2,513	--	213
Interest receivable - restricted	--	88	13	--	--
Receivables from other governments	--	--	--	--	--
Inventories, at cost	--	--	--	--	--
Prepaid expenses	--	31	51	--	--
Other receivables - restricted	--	--	3,800	--	--
Total current assets	89	68,104	38,665	1,188	286
Noncurrent assets:					
Advances to other funds	--	--	41	23	--
Capital assets					
Land and other nondepreciable assets	--	26,314	2,960	324	803
Property, plant and equipment in service	9	234,762	46,668	12,241	73,990
Less accumulated depreciation	(1)	(30,026)	(7,930)	(3,844)	(37,363)
Net property, plant and equipment in service	8	204,736	38,738	8,397	36,627
Construction in progress	452	22,045	21,797	2,638	--
Total capital assets	460	253,095	63,495	11,359	37,430
Deferred costs and expenses, net of amortization	--	18,326	7	13	--
Total noncurrent assets	460	271,421	63,543	11,395	37,430
Total assets	$ 549	339,525	102,208	12,583	37,716

	Parks and Recreation	Primary Care	Solid Waste Services	Trans-portation	2003 Total
ASSETS					
Current assets:					
Cash	--	2	3	1	17
Pooled investments and cash	142	2,292	5,765	5,326	29,825
Pooled investments and cash - designated	--	--	7,045	--	19,625
Pooled investments and cash - restricted	--	--	1,323	4	59,153
Total pooled investments and cash	142	2,292	14,133	5,330	108,603
Investments, at fair value - designated	--	--	--	--	297
Investments, at fair value - restricted	--	--	--	--	14,011
Working capital advances	--	--	--	--	124
Accounts receivable	--	2,236	4,576	1,628	14,852
Less allowance for doubtful accounts	--	(40)	(154)	(466)	(3,872)
Net accounts receivable	--	2,196	4,422	1,162	10,980
Interest receivable - restricted	--	--	--	--	101
Receivables from other governments	--	326	--	--	326
Inventories, at cost	--	349	--	198	547
Prepaid expenses	--	29	20	--	131
Other receivables - restricted	--	--	--	--	3,800
Total current assets	142	5,194	18,578	6,691	138,937
Noncurrent assets:					
Advances to other funds	--	--	--	--	64
Capital assets					
Land and other nondepreciable assets	--	--	10,662	--	41,063
Property, plant and equipment in service	173	1,087	54,363	12,332	435,625
Less accumulated depreciation	(59)	(574)	(24,314)	(6,171)	(110,282)
Net property, plant and equipment in service	114	513	30,049	6,161	325,343
Construction in progress	--	1	2,937	--	49,870
Total capital assets	114	514	43,648	6,161	416,276
Deferred costs and expenses, net of amortization	--	--	29	--	18,375
Total noncurrent assets	114	514	43,677	6,161	434,715
Total assets	256	5,708	62,255	12,852	573,652

(Continued)

Nonmajor Enterprise Funds
Combining Statement of Net Assets
September 30, 2003
(In thousands)

	Austin Women's Hospital	Convention Center	Drainage	Golf	Hospital
LIABILITIES					
Current liabilities:					
Accounts payable	$ 8	164	1,854	93	48
Accounts and retainage payable from restricted assets	--	1,592	760	5	--
Accrued payroll	--	210	410	81	3
Accrued compensated absences	--	328	848	144	2
Accrued interest payable from restricted assets	--	5,061	--	--	--
Interest payable on other debt	--	--	56	34	--
General obligation bonds payable and other tax supported debt	--	--	611	497	--
General obligation bonds payable and other tax supported debt payable from restricted assets	--	390	--	--	--
Revenue bonds payable from restricted assets	--	5,210	--	--	--
Capital lease obligations payable	--	42	41	--	--
Customer and escrow deposits payable from restricted assets	--	1,332	631	--	--
Deferred credits and other liabilities	--	--	--	5	--
Total current liabilities	8	14,329	5,211	859	53
Noncurrent liabilities, net of current portion:					
Accrued compensated absences	--	200	522	130	--
Advances from other funds	--	2,520	--	--	--
General obligation bonds payable and other tax supported debt, net of discount and inclusive of premium	--	9,397	13,740	7,926	--
Revenue bonds payable, net of discount and inclusive of premium	--	228,836	--	--	--
Capital lease obligations payable	--	18	46	--	--
Accrued landfill closure and postclosure costs	--	--	--	--	--
Total noncurrent liabilities	--	240,971	14,308	8,056	--
Total liabilities	8	255,300	19,519	8,915	53
NET ASSETS					
Invested in capital assets, net of related debt	8	40,554	49,627	3,390	37,430
Restricted for:					
Debt service	--	7,254	--	--	--
Capital projects	--	--	12,998	--	--
Renewal and replacement	--	1,330	--	--	--
Convention Center operating reserve	--	1,957	--	--	--
Unrestricted	533	33,130	20,064	278	233
Total net assets	$ 541	84,225	82,689	3,668	37,663

	Parks and Recreation	Primary Care	Solid Waste Services	Trans-portation	2003 Total
LIABILITIES					
Current liabilities:					
Accounts payable	33	940	698	1,570	5,408
Accounts and retainage payable from restricted assets	--	--	371	--	2,728
Accrued payroll	49	363	475	240	1,831
Accrued compensated absences	35	606	904	594	3,461
Accrued interest payable from restricted assets	--	--	--	--	5,061
Interest payable on other debt	--	--	89	4	183
General obligation bonds payable and other tax supported debt	--	--	1,942	130	3,180
General obligation bonds payable and other tax supported debt payable from restricted assets	--	--	--	--	390
Revenue bonds payable from restricted assets	--	--	--	--	5,210
Capital lease obligations payable	1	--	41	8	133
Customer and escrow deposits payable from restricted assets	--	--	306	--	2,269
Deferred credits and other liabilities	--	89	294	--	388
Total current liabilities	118	1,998	5,120	2,546	30,242
Noncurrent liabilities, net of current portion:					
Accrued compensated absences	16	133	245	221	1,467
Advances from other funds	--	--	1,176	--	3,696
General obligation bonds payable and other tax supported debt, net of discount and inclusive of premium	--	--	15,478	67	46,608
Revenue bonds payable, net of discount and inclusive of premium	--	--	--	--	228,836
Capital lease obligations payable	--	--	33	10	107
Accrued landfill closure and postclosure costs	--	--	7,370	--	7,370
Total noncurrent liabilities	16	133	24,302	298	288,084
Total liabilities	134	2,131	29,422	2,844	318,326
NET ASSETS					
Invested in capital assets, net of related debt	113	514	26,828	5,952	164,416
Restricted for:					
Debt service	--	--	--	--	7,254
Capital projects	--	--	--	--	12,998
Renewal and replacement	--	--	--	--	1,330
Convention Center operating reserve	--	--	--	--	1,957
Unrestricted	9	3,063	6,005	4,056	67,371
Total net assets	122	3,577	32,833	10,008	255,326

Nonmajor Enterprise Funds
Combining Statement of Revenues, Expenses and Changes in Fund Net Assets
For the year ended September 30, 2003
(In thousands)

	Austin Women's Hospital	Convention Center	Drainage	Golf	Hospital
OPERATING REVENUES					
User fees and rentals	$ --	15,040	31,419	5,671	238
Operating revenues from other governments	--	--	--	--	--
Other operating revenues	573	--	--	--	--
Total operating revenues	573	15,040	31,419	5,671	238
OPERATING EXPENSES					
Operating expenses before depreciation	32	21,778	24,893	4,877	144
Depreciation and amortization	1	5,270	1,690	370	1,167
Total operating expenses	33	27,048	26,583	5,247	1,311
Operating income (loss)	540	(12,008)	4,836	424	(1,073)
NONOPERATING REVENUES (EXPENSES)					
Interest and other revenues	1	893	924	21	22
Interest on revenue bonds and other debt	--	(14,517)	(409)	(426)	--
Interest capitalized during construction	--	1,052	458	94	--
Amortization of bond issue cost	--	(168)	--	(1)	--
Other nonoperating revenue (expense)	--	60	(12)	(17)	--
Total nonoperating revenues (expenses)	1	(12,680)	961	(329)	22
Income (loss) before contributions and transfers	541	(24,688)	5,797	95	(1,051)
Capital contributions	--	--	1,581	85	--
Transfers in	--	22,895	299	--	--
Transfers out	--	(75)	(837)	--	--
Change in net assets	541	(1,868)	6,840	180	(1,051)
Total net assets - beginning	--	86,093	75,849	3,488	38,714
Total net assets - ending	$ 541	84,225	82,689	3,668	37,663

	Parks and Recreation	Primary Care	Solid Waste Services	Trans-portation	2003 Total
OPERATING REVENUES					
User fees and rentals	3,652	10,717	40,534	20,759	128,030
Operating revenues from other governments	–	2,269	–	–	2,269
Other operating revenues	–	2,037	–	–	2,610
Total operating revenues	3,652	15,023	40,534	20,759	132,909
OPERATING EXPENSES					
Operating expenses before depreciation	3,484	21,943	34,306	19,435	130,892
Depreciation and amortization	9	51	3,207	1,036	12,801
Total operating expenses	3,493	21,994	37,513	20,471	143,693
Operating income (loss)	159	(6,971)	3,021	288	(10,784)
NONOPERATING REVENUES (EXPENSES)					
Interest and other revenues	1	36	294	96	2,288
Interest on revenue bonds and other debt	–	–	(949)	(11)	(16,312)
Interest capitalized during construction	–	–	210	–	1,814
Amortization of bond issue cost	–	–	(4)	–	(173)
Other nonoperating revenue (expense)	(2)	(7)	(1,821)	(23)	(1,822)
Total nonoperating revenues (expenses)	(1)	29	(2,270)	62	(14,205)
Income (loss) before contributions and transfers	158	(6,942)	751	350	(24,989)
Capital contributions	–	–	43	(30)	1,679
Transfers in	–	7,729	1,111	–	32,034
Transfers out	–	–	(643)	(206)	(1,761)
Change in net assets	158	787	1,262	114	6,963
Total net assets - beginning	(36)	2,790	31,571	9,894	248,363
Total net assets - ending	122	3,577	32,833	10,008	255,326

Nonmajor Enterprise Funds
Combining Statement of Cash Flows
For the year ended September 30, 2003
(In thousands)

	Austin Women's Hospital	Convention Center	Drainage	Golf	Hospital
CASH FLOWS FROM OPERATING ACTIVITIES:					
Cash received from customers	$ 573	15,202	31,297	5,670	2,034
Cash payments to suppliers for goods and services	(2)	(15,413)	(9,372)	(2,067)	(763)
Cash payments to employees for services	(30)	(6,736)	(14,651)	(2,777)	(88)
Cash received from other governments	–	–	–	–	–
Net cash provided (used) by operating activities	541	(6,947)	7,274	826	1,183
CASH FLOWS FROM NONCAPITAL FINANCING ACTIVITIES:					
Transfers in	–	22,895	299	–	–
Transfers out	–	(75)	(837)	–	–
Interest paid on revenue notes and other debt	–	–	–	–	–
Loans to other funds	–	–	(17)	(23)	–
Loans from other funds	–	2,520	–	–	–
Loan repayments to other funds	–	–	–	(44)	(1,198)
Loan repayments from other funds	–	–	491	–	–
Net cash provided (used) by noncapital financing activities	–	25,340	(64)	(67)	(1,198)
CASH FLOWS FROM CAPITAL AND RELATED FINANCING ACTIVITIES:					
Principal paid on long-term debt	–	(3,680)	(525)	(446)	–
Purchased interest received	–	–	–	13	–
Interest paid on revenue bonds and other debt	–	(13,978)	(478)	(399)	–
Acquisition and construction of capital assets	(453)	(7,179)	(11,061)	(474)	–
Contributions in aid of construction	–	–	1,999	85	–
Bond issuance costs	–	–	–	(6)	–
Bond discounts	–	–	–	(11)	–
Bond premiums	–	–	–	312	–
Bonds issued for advanced refundings of debt	–	–	–	2,948	–
Cash paid for bond refunding escrow	–	–	–	(3,244)	–
Net cash provided (used) by capital and related financing activities	$ (453)	(24,837)	(10,065)	(1,222)	–

	Parks and Recreation	Primary Care	Solid Waste Services	Trans-portation	2003 Total
CASH FLOWS FROM OPERATING ACTIVITIES:					
Cash received from customers	3,652	9,387	40,638	20,641	129,094
Cash payments to suppliers for goods and services	(1,229)	(6,119)	(17,002)	(9,482)	(61,449)
Cash payments to employees for services	(2,335)	(13,632)	(17,103)	(9,110)	(66,462)
Cash received from other governments	–	2,686	–	–	2,686
Net cash provided (used) by operating activities	88	(7,678)	6,533	2,049	3,869
CASH FLOWS FROM NONCAPITAL FINANCING ACTIVITIES:					
Transfers in	–	7,729	1,111	–	32,034
Transfers out	–	–	(643)	(206)	(1,761)
Interest paid on revenue notes and other debt	–	–	(2)	–	(2)
Loans to other funds	–	–	–	–	(40)
Loans from other funds	–	–	536	–	3,056
Loan repayments to other funds	–	–	–	–	(1,242)
Loan repayments from other funds	–	1,198	–	–	1,689
Net cash provided (used) by noncapital financing activities	–	8,927	1,002	(206)	33,734
CASH FLOWS FROM CAPITAL AND RELATED FINANCING ACTIVITIES:					
Principal paid on long-term debt	–	–	(2,016)	(129)	(6,796)
Purchased interest received	–	–	5	–	18
Interest paid on revenue bonds and other debt	–	–	(966)	(13)	(15,834)
Acquisition and construction of capital assets	(7)	(184)	(1,953)	(912)	(22,223)
Contributions in aid of construction	–	–	43	–	2,127
Bond issuance costs	–	–	(2)	–	(8)
Bond discounts	–	–	(4)	–	(15)
Bond premiums	–	–	133	–	445
Bonds issued for advanced refundings of debt	–	–	1,257	–	4,205
Cash paid for bond refunding escrow	–	–	(1,383)	–	(4,627)
Net cash provided (used) by capital and related financing activities	(7)	(184)	(4,886)	(1,054)	(42,708)

(Continued)

Nonmajor Enterprise Funds
Combining Statement of Cash Flows
For the year ended September 30, 2003
(In thousands)

	Austin Women's Hospital	Convention Center	Drainage	Golf	Hospital
CASH FLOWS FROM INVESTING ACTIVITIES:					
Purchase of investment securities	$ --	(36,031)	--	--	--
Proceeds from sale and maturities of investment securities	--	34,611	--	--	--
Interest on investments	1	1,084	921	21	22
Net cash provided by investing activities	1	(336)	921	21	22
Net increase (decrease) in cash and cash equivalents	89	(6,780)	(1,934)	(442)	7
Cash and cash equivalents, October 1	--	59,859	34,222	1,630	66
Cash and cash equivalents, September 30	89	53,079	32,288	1,188	73
RECONCILIATION OF OPERATING INCOME TO NET CASH PROVIDED (USED) BY OPERATING ACTIVITIES:					
Operating income (loss)	540	(12,008)	4,836	424	(1,073)
Adjustments to reconcile operating income to net cash provided by operating activities:					
Depreciation	1	5,270	1,690	370	1,167
Change in assets and liabilities:					
(Increase) decrease in accounts receivable	--	(151)	(134)	--	2,055
Increase (decrease) in allowance for doubtful accounts	--	(5)	12	--	(104)
Decrease in receivable from other governments	--	--	--	--	--
(Increase) decrease in inventory	--	--	--	--	--
(Increase) decrease in prepaid expenses and other assets	--	--	(3)	--	--
Increase (decrease) in accounts payable	--	(342)	789	41	(708)
Increase (decrease) in accrued payroll and compensated absences	--	(28)	84	(9)	1
Increase (decrease) in deferred credits and other liabilities	--	--	--	--	(155)
Increase in customer deposits	--	317	--	--	--
Total adjustments	1	5,061	2,438	402	2,256
Net cash provided (used) by operating activities	$ 541	(6,947)	7,274	826	1,183
NONCASH INVESTING, CAPITAL AND FINANCING ACTIVITIES:					
Capital assets contributed from (to) other funds	$ --	--	--	--	--
Net increase (decrease) in the fair value of investments	--	(13)	--	--	--
Amortization of bond issue costs	--	(168)	--	(1)	--
Amortization of bond discounts and premiums	--	176	(2)	(30)	--
Amortization of deferred loss on refundings	--	427	1	11	--
Gain (loss) on disposal of assets	--	61	(11)	(36)	--
Deferred gain and loss on bond refunding	--	--	--	(229)	--
Bond issuance costs, discounts, premiums and accrued interest written off due to refunding	--	--	--	32	--
Deferred costs recovered	--	--	--	(11)	--
Loss on extinguishment of debt	--	--	--	230	--
Contributions from other funds	--	--	--	(31)	--
Capital lease obligations	--	115	138	--	--
General obligation bonds and other tax supported debt proceeds receivable	--	--	3,800	--	--

	Parks and Recreation	Primary Care	Solid Waste Services	Trans-portation	2003 Total
CASH FLOWS FROM INVESTING ACTIVITIES:					
Purchase of investment securities	–	–	–	–	(36,031)
Proceeds from sale and maturities of investment securities	–	–	–	–	34,611
Interest on investments	1	36	262	96	2,444
Net cash provided by investing activities	1	36	262	96	1,024
Net increase (decrease) in cash and cash equivalents	82	1,101	2,911	885	(4,081)
Cash and cash equivalents, October 1	60	1,193	11,225	4,446	112,701
Cash and cash equivalents, September 30	142	2,294	14,136	5,331	108,620
RECONCILIATION OF OPERATING INCOME TO NET CASH PROVIDED (USED) BY OPERATING ACTIVITIES:					
Operating income (loss)	159	(6,971)	3,021	288	(10,784)
Adjustments to reconcile operating income to net cash provided by operating activities:					
Depreciation	9	51	3,207	1,036	12,801
Change in assets and liabilities:					
(Increase) decrease in accounts receivable	–	(1,336)	20	(118)	336
Increase (decrease) in allowance for doubtful accounts	–	–	2	222	127
Decrease in receivable from other governments	–	417	–	–	417
(Increase) decrease in inventory	–	(11)	–	9	(2)
(Increase) decrease in prepaid expenses and other assets	–	(1)	25	–	21
Increase (decrease) in accounts payable	(58)	52	(74)	594	294
Increase (decrease) in accrued payroll and compensated absences	(22)	115	69	18	228
Increase (decrease) in deferred credits and other liabilities	–	6	182	–	33
Increase in customer deposits	–	–	81	–	398
Total adjustments	(71)	(707)	3,512	1,761	14,653
Net cash provided (used) by operating activities	88	(7,678)	6,533	2,049	3,869
NONCASH INVESTING, CAPITAL AND FINANCING ACTIVITIES:					
Capital assets contributed from (to) other funds	–	–	–	8	8
Net increase (decrease) in the fair value of investments	–	–	–	–	(13)
Amortization of bond issue costs	–	–	(4)	–	(173)
Amortization of bond discounts and premiums	–	–	(55)	–	89
Amortization of deferred loss on refundings	–	–	(57)	–	382
Gain (loss) on disposal of assets	(2)	(7)	(1,821)	(23)	(1,839)
Deferred gain and loss on bond refunding	–	–	98	–	(131)
Bond issuance costs, discounts, premiums and accrued interest written off due to refunding	–	–	13	–	45
Deferred costs recovered	–	–	–	–	(11)
Loss on extinguishment of debt	–	–	–	–	230
Contributions from other funds	–	–	–	–	(31)
Capital lease obligations	1	–	124	25	403
General obligation bonds and other tax supported debt proceeds receivable	–	–	–	–	3,800

CITY OF AUSTIN
FOUNDED 1839

INTERNAL SERVICE FUNDS

Internal service funds are used to account for the financing of goods or services provided by one department to other departments of the City and other agencies on a cost-reimbursement basis.

The internal service funds are as follows:

- The Capital Projects Management Fund, which manages the City's capital improvement projects
- The Employee Benefits Fund, which includes activities related to the health, dental, and life insurance costs of City employees;
- The Fleet Maintenance Fund, which includes vehicle and equipment services;
- The Information Systems Fund, which includes activities of the Information Systems Department;
- The Liability Reserve Fund, which provides coverage of the City's major claims liabilities;
- The Support Services Fund, which includes the activities of the various support service departments;
- The Wireless Communication Fund, which includes communication support activities; and
- The Workers' Compensation Fund, which accounts for workers' compensation costs.

CITY OF AUSTIN
FOUNDED 1839

Internal Service Funds
Combining Statement of Net Assets
September 30, 2003
(In thousands)

	Capital Projects Management	Employee Benefits	Fleet Maintenance	Information Systems	Liability Reserve
ASSETS					
Current assets:					
Cash	$ 3	–	3	–	–
Pooled investments and cash	5,016	14,372	8,086	5,479	5,177
Cash held by trustee	–	488	–	–	–
Accounts receivable	293	421	307	–	9,090
Less allowance for doubtful accounts	–	–	(222)	–	–
Net accounts receivable	293	421	85	–	9,090
Inventories, at cost	–	–	1,594	–	–
Prepaid expenses	20	–	–	–	–
Total current assets	5,332	15,281	9,768	5,479	14,267
Noncurrent assets:					
Capital assets					
Land and other nondepreciable assets	–	–	–	–	–
Property, plant and equipment in service	1,034	–	27,671	21,556	–
Less accumulated depreciation	(361)	–	(13,490)	(5,716)	–
Net property, plant and equipment in service	673	–	14,181	15,840	–
Construction in progress	–	–	1,043	3,448	–
Total capital assets	673	–	15,224	19,288	–
Deferred costs and expenses, net of amortization	–	–	4	2	–
Total noncurrent assets	673	–	15,228	19,290	–
Total assets	$ 6,005	15,281	24,996	24,769	14,267

	Support Services	Wireless Communication	Workers' Compensation	2003 Total
ASSETS				
Current assets:				
Cash	11	1	–	18
Pooled investments and cash	10,191	502	11,230	60,053
Cash held by trustee	–	–	–	488
Accounts receivable	481	52	–	10,644
Less allowance for doubtful accounts	–	–	–	(222)
Net accounts receivable	481	52	–	10,422
Inventories, at cost	–	135	–	1,729
Prepaid expenses	238	–	–	258
Total current assets	10,921	690	11,230	72,968
Noncurrent assets:				
Capital assets				
Land and other nondepreciable assets	486	–	–	486
Property, plant and equipment in service	6,638	593	–	57,492
Less accumulated depreciation	(3,102)	(208)	–	(22,877)
Net property, plant and equipment in service	3,536	385	–	34,615
Construction in progress	–	–	–	4,491
Total capital assets	4,022	385	–	39,592
Deferred costs and expenses, net of amortization	1	–	–	7
Total noncurrent assets	4,023	385	–	39,599
Total assets	14,944	1,075	11,230	112,567

(Continued)

Internal Service Funds
Combining Statement of Net Assets
September 30, 2003
(In thousands)

	Capital Projects Management	Employee Benefits	Fleet Maintenance	Information Systems	Liability Reserve
LIABILITIES					
Current liabilities:					
Accounts payable	$ 146	2,271	1,259	404	230
Accrued payroll	389	–	276	390	–
Accrued compensated absences	762	–	491	765	–
Claims payable	–	5,541	–	–	10,535
Due to other funds	–	–	–	27	–
Interest payable on other debt	–	–	57	81	–
General obligation bonds payable and other tax supported debt	–	–	640	1,322	–
Capital lease obligations payable	46	–	24	171	–
Deferred credits and other liabilities	–	488	–	–	–
Total current liabilities	1,343	8,300	2,747	3,160	10,765
Noncurrent liabilities, net of current portion:					
Accrued compensated absences	575	–	187	273	–
Claims payable	–	–	–	–	9,545
Advances from other funds	–	–	122	188	–
General obligation bonds payable and other tax supported debt, net of discount and inclusive of premium	–	–	7,760	4,364	–
Capital lease obligations payable	22	–	20	46	–
Total noncurrent liabilities	597	–	8,089	4,871	9,545
Total liabilities	1,940	8,300	10,836	8,031	20,310
NET ASSETS					
Invested in capital assets, net of related debt	605	–	5,741	11,969	–
Restricted for:					
Capital projects	–	–	5,608	1,529	–
Unrestricted (deficit)	3,460	6,981	2,811	3,240	(6,043)
Total net assets	$ 4,065	6,981	14,160	16,738	(6,043)

	Support Services	Wireless Communication	Workers' Compensation	2003 Total
LIABILITIES				
Current liabilities:				
Accounts payable	1,626	12	278	6,226
Accrued payroll	1,134	53	--	2,242
Accrued compensated absences	2,124	65	--	4,207
Claims payable	--	--	4,045	20,121
Due to other funds	--	--	--	27
Interest payable on other debt	4	--	--	142
General obligation bonds payable and other tax supported debt	152	--	--	2,114
Capital lease obligations payable	65	11	--	317
Deferred credits and other liabilities	96	305	--	889
Total current liabilities	5,201	446	4,323	36,285
Noncurrent liabilities, net of current portion:				
Accrued compensated absences	1,514	62	--	2,611
Claims payable	--	--	5,082	14,627
Advances from other funds	86	--	--	396
General obligation bonds payable and other tax supported debt, net of discount and inclusive of premium	653	--	--	12,777
Capital lease obligations payable	30	2	--	120
Total noncurrent liabilities	2,283	64	5,082	30,531
Total liabilities	7,484	510	9,405	66,816
NET ASSETS				
Invested in capital assets, net of related debt	2,637	372	--	21,324
Restricted for:				
Capital projects	--	--	--	7,137
Unrestricted (deficit)	4,823	193	1,825	17,290
Total net assets	7,460	565	1,825	45,751

Internal Service Funds
Combining Statement of Revenues, Expenses and Changes in Fund Net Assets
For the year ended September 30, 2003
(In thousands)

	Capital Projects Management	Employee Benefits	Fleet Maintenance	Information Systems	Liability Reserve
OPERATING REVENUES					
Billings to departments	$ 16,373	57,682	23,614	24,663	4,510
Employee contributions	--	22,073	--	--	--
Other operating revenues	2,318	--	156	166	9,090
Total operating revenues	18,691	79,755	23,770	24,829	13,600
OPERATING EXPENSES					
Operating expenses before depreciation	18,037	82,554	23,268	22,080	10,827
Depreciation and amortization	147	--	345	620	--
Total operating expenses	18,184	82,554	23,613	22,700	10,827
Operating income (loss)	507	(2,799)	157	2,129	2,773
NONOPERATING REVENUES (EXPENSES)					
Interest and other revenues	81	--	--	93	--
Interest on revenue bonds and other debt	--	--	(357)	(206)	--
Amortization of bond issue cost	--	--	(2)	--	--
Other nonoperating revenue (expense)	64	--	95	238	--
Total nonoperating revenues (expenses)	145	--	(264)	125	--
Income (loss) before contributions and transfers	652	(2,799)	(107)	2,254	2,773
Capital contributions	--	--	(1,685)	787	--
Transfers out	--	--	--	(79)	--
Change in net assets	652	(2,799)	(1,792)	2,962	2,773
Total net assets - beginning	3,413	9,780	15,952	13,776	(8,816)
Total net assets - ending	$ 4,065	6,981	14,160	16,738	(6,043)

	Support Services	Wireless Communication	Workers' Compensation	2003 Total
OPERATING REVENUES				
Billings to departments	49,952	2,602	11,065	190,461
Employee contributions	--	--	--	22,073
Other operating revenues	--	35	--	11,765
Total operating revenues	49,952	2,637	11,065	224,299
OPERATING EXPENSES				
Operating expenses before depreciation	47,736	2,673	11,564	218,739
Depreciation and amortization	514	71	--	1,697
Total operating expenses	48,250	2,744	11,564	220,436
Operating income (loss)	1,702	(107)	(499)	3,863
NONOPERATING REVENUES (EXPENSES)				
Interest and other revenues	250	11	--	435
Interest on revenue bonds and other debt	(47)	--	--	(610)
Amortization of bond issue cost	(2)	--	--	(4)
Other nonoperating revenue (expense)	51	11	--	459
Total nonoperating revenues (expenses)	252	22	--	280
Income (loss) before contributions and transfers	1,954	(85)	(499)	4,143
Capital contributions	304	--	--	(594)
Transfers out	(77)	--	--	(156)
Change in net assets	2,181	(85)	(499)	3,393
Total net assets - beginning	5,279	650	2,324	42,358
Total net assets - ending	7,460	565	1,825	45,751

Internal Service Funds
Combining Statement of Cash Flows
For the year ended September 30, 2003
(In thousands)

	Capital Projects Management	Employee Benefits	Fleet Maintenance	Information Systems	Liability Reserve
CASH FLOWS FROM OPERATING ACTIVITIES:					
Cash received from customers	$ 18,642	79,334	23,744	24,842	4,510
Cash payments to suppliers for goods and services	(4,171)	(31,253)	(12,510)	(7,546)	(1,053)
Cash payments to employees for services	(13,884)	--	(10,061)	(14,891)	--
Cash payments to claimants/beneficiaries	--	(49,957)	--	--	(11,405)
Net cash provided (used) by operating activities	587	(1,876)	1,173	2,405	(7,948)
CASH FLOWS FROM NONCAPITAL FINANCING ACTIVITIES:					
Transfers out	--	--	--	(79)	--
Loans from other funds	--	--	59	--	--
Loan repayments to other funds	--	--	--	(27)	--
Net cash provided (used) by noncapital financing activities	--	--	59	(106)	--
CASH FLOWS FROM CAPITAL AND RELATED FINANCING ACTIVITIES:					
Principal paid on long-term debt	(59)	--	(454)	(1,303)	--
Interest paid on revenue bonds and other debt	--	--	(331)	(183)	--
Acquisition and construction of capital assets	(20)	--	(5,148)	(5,626)	--
Contributions from municipality	--	--	1,346	943	--
Net cash used by capital and related financing activities	$ (79)	--	(4,587)	(6,169)	--

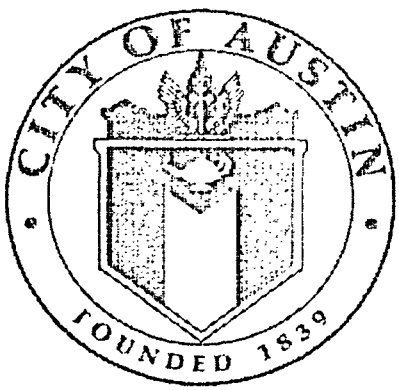
	Support Services	Wireless Communication	Workers' Compensation	2003 Total
CASH FLOWS FROM OPERATING ACTIVITIES:				
Cash received from customers	49,508	2,487	11,065	214,132
Cash payments to suppliers for goods and services	(5,535)	(814)	(1,191)	(64,073)
Cash payments to employees for services	(41,657)	(1,773)	--	(82,266)
Cash payments to claimants/beneficiaries	--	--	(8,190)	(69,552)
Net cash provided (used) by operating activities	2,316	(100)	1,684	(1,759)
CASH FLOWS FROM NONCAPITAL FINANCING ACTIVITIES:				
Transfers out	(77)	--	--	(156)
Loans from other funds	--	--	--	59
Loan repayments to other funds	--	--	--	(27)
Net cash provided (used) by noncapital financing activities	(77)	--	--	(124)
CASH FLOWS FROM CAPITAL AND RELATED FINANCING ACTIVITIES:				
Principal paid on long-term debt	(225)	(12)	--	(2,053)
Interest paid on revenue bonds and other debt	(49)	--	--	(563)
Acquisition and construction of capital assets	(59)	--	--	(10,853)
Contributions from municipality	186	--	--	2,475
Net cash used by capital and related financing activities	(147)	(12)	--	(10,994)

(Continued)

Internal Service Funds
Combining Statement of Cash Flows
For the year ended September 30, 2003
(In thousands)

	Capital Projects Management	Employee Benefits	Fleet Maintenance	Information Systems	Liability Reserve
CASH FLOWS FROM INVESTING ACTIVITIES:					
Interest on investments	$ 81	–	–	93	–
Net cash provided by investing activities	81	–	–	93	–
Net increase (decrease) in cash and cash equivalents	589	(1,876)	(3,355)	(3,777)	(7,948)
Cash and cash equivalents, October 1	4,430	16,736	11,444	9,256	13,125
Cash and cash equivalents, September 30	5,019	14,860	8,089	5,479	5,177
RECONCILIATION OF OPERATING INCOME TO NET CASH PROVIDED (USED) BY OPERATING ACTIVITIES:					
Operating income (loss)	507	(2,799)	157	2,129	2,773
Adjustments to reconcile operating income to net cash provided by operating activities:					
Depreciation	147	–	345	620	–
Change in assets and liabilities:					
(Increase) decrease in accounts receivable	(20)	(421)	(26)	13	(9,090)
Decrease in inventory	–	–	324	–	–
Increase in prepaid expenses and other assets	(20)	–	–	–	–
Increase (decrease) in accounts payable	(132)	335	292	(117)	188
Increase (decrease) in accrued payroll and compensated absences	134	–	81	(240)	–
Increase (decrease) in claims payable	–	923	–	–	(1,819)
Increase (decrease) in deferred credits and other liabilities	(29)	86	–	–	–
Total adjustments	80	923	1,016	276	(10,721)
Net cash provided (used) by operating activities	$ 587	(1,876)	1,173	2,405	(7,948)
NONCASH INVESTING, CAPITAL AND FINANCING ACTIVITIES:					
Increase in advances from other funds	$ –	–	–	–	–
Capital assets contributed from (to) other funds	–	–	(3,031)	(156)	–
Amortization of bond discounts and premiums	–	–	(1)	–	–
Amortization of deferred loss on refundings	–	–	3	–	–
Gain (loss) on disposal of assets	–	–	73	(4)	–
Contributions from other funds	–	–	–	–	–
Capital lease obligations	127	–	74	422	–
General obligation bonds and other tax supported debt proceeds receivable	–	–	–	–	9,090

	Support Services	Wireless Communication	Workers' Compensation	2003 Total
CASH FLOWS FROM INVESTING ACTIVITIES:				
Interest on investments	250	11	–	435
Net cash provided by investing activities	250	11	–	435
Net increase (decrease) in cash and cash equivalents	2,342	(101)	1,684	(12,442)
Cash and cash equivalents, October 1	7,860	604	9,546	73,001
Cash and cash equivalents, September 30	10,202	503	11,230	60,559
RECONCILIATION OF OPERATING INCOME TO NET CASH PROVIDED (USED) BY OPERATING ACTIVITIES:				
Operating income (loss)	1,702	(107)	(499)	3,863
Adjustments to reconcile operating income to net cash provided by operating activities:				
Depreciation	514	71	–	1,697
Change in assets and liabilities:				
(Increase) decrease in accounts receivable	(444)	86	–	(9,902)
Decrease in inventory	–	48	–	372
Increase in prepaid expenses and other assets	–	–	–	(20)
Increase (decrease) in accounts payable	246	(5)	(80)	727
Increase (decrease) in accrued payroll and compensated absences	287	43	–	305
Increase (decrease) in claims payable	–	–	2,263	1,367
Increase (decrease) in deferred credits and other liabilities	11	(236)	–	(168)
Total adjustments	614	7	2,183	(5,622)
Net cash provided (used) by operating activities	2,316	(100)	1,684	(1,759)
NONCASH INVESTING, CAPITAL AND FINANCING ACTIVITIES:				
Increase in advances from other funds	42	–	–	42
Capital assets contributed from (to) other funds	160	–	–	(3,027)
Amortization of bond discounts and premiums	(1)	–	–	(2)
Amortization of deferred loss on refundings	3	–	–	6
Gain (loss) on disposal of assets	(48)	–	–	21
Contributions from other funds	144	–	–	144
Capital lease obligations	182	25	–	830
General obligation bonds and other tax supported debt proceeds receivable	–	–	–	9,090


CITY OF AUSTIN
FOUNDED 1839

FIDUCIARY FUNDS

Fiduciary funds account for assets held by the City in a trustee capacity or as an agent for other agencies, individuals, private organizations, or governmental units. Included in the fiduciary funds are private-purpose trust funds and agency funds.

- Private-purpose trust funds accounts are used to report trust arrangements under which principal and interest income benefits individuals, private organizations, or other governments.
- Agency funds are purely custodial and thus do not involve measurement of results of operations.

See next page for descriptions of the individual funds.

Private-Purpose Trust Funds

Barbara Jordan Memorial Fund - Purpose is to account for donations for a future memorial.

COA Customer Assistance - Purpose is to hold donations solicited to help pay utility bills (part of Plus One Program). Funded by businesses that can use the donation as a tax deduction.

First Step-A Community Project - Accounts for programs and activities to improve community relations.

Leveraged Loan Pool - Purpose is to hold funds used to leverage private capital and state or federal resources to stimulate business investments.

Library City Literacy Program – Purpose is to account for fundraising efforts to help fund the City's Workplace Literacy Program.

Telecommunity Partnership Fund – Purpose is to account for addressing the training needs of the Austin community and creating opportunities for individuals through partnerships with local employers.

Unclaimed Property – Purpose is to account for unclaimed City of Austin checks.

Voluntary Utility Assistance – Purpose is to account for contributions for the benefit of indigent utility customers. Contributions are received with electric bill payments.

Agency Funds

BCCP Permit Fund – Purpose is to hold BCCP Permit fees collected on behalf of Travis County.

Campaign Financing Fund – Purpose is to account for donations and fees for the Austin Fair Campaign Ordinance.

Municipal Court Fund – Purpose is to record service fees collected at Municipal Court that will be remitted to the State Comptroller of Public Accounts.

Municipal Utility District Funds – Purpose is to account for revenues received from municipal utility districts which are used to make debt service payments for the districts.

Neighborhood Revitalization Funds – Purpose is to account for escrow deposits and payments to loan recipients.

Fiduciary Funds
Private-Purpose Trust Funds
Combining Statement of Fiduciary Net Assets
September 30, 2003
(In thousands)

City of Austin, Texas
Exhibit H-1

	Assets			Liabilities			Net Assets Held in Trust
	Pooled Investments and Cash	Other Assets	Total Assets	Accounts Payable	Other Liabilities	Total Liabilities	
General government							
Unclaimed Property	$ 261	–	261	–	253	253	8
Total general government	261	–	261	–	253	253	8
Transportation, planning and sustainability							
COA Customer Service	–	–	–	–	–	–	–
Voluntary Utility Assistance	116	–	116	–	–	–	116
Total transportation, planning and sustainability	116	–	116	–	–	–	116
Public recreation and culture							
Barbara Jordan Memorial	1	–	1	–	–	–	1
First Step - A Community Project	130	–	130	1	–	1	129
Library City Literacy Program	3	–	3	–	–	–	3
Total public recreation and culture	134	–	134	1	–	1	133
Urban growth management							
Leveraged Loan Pool	360	121	481	–	–	–	481
Telecommunity Partnership	13	–	13	–	–	–	13
Total urban growth management	373	121	494	–	–	–	494
2003 Total	$ 884	121	1,005	1	253	254	751

Fiduciary Funds
Private-Purpose Trust Funds
Combining Statement of Changes in Fiduciary Net Assets
For the year ended September 30, 2003
(In thousands)

	Additions					Net Assets at Beginning of Year	Net Assets at End of Year
	Contributions	Interest and Other	Total Additions	Deductions (1)	Net Increase (Decrease)		
General government							
Unclaimed Property	$ –	5	5	6	(1)	9	8
Total general government	–	5	5	6	(1)	9	8
Transportation, planning and sustainability							
COA Customer Service	2	–	2	11	(9)	9	–
Voluntary Utility Assistance	215	2	217	37	180	(64)	116
Total transportation, planning and sustainability	217	2	219	48	171	(55)	116
Public recreation and culture							
Barbara Jordan Memorial	–	–	–	–	–	1	1
First Step - A Community Project	–	4	4	103	(99)	228	129
Library City Literacy Program	–	–	–	–	–	3	3
Total public recreation and culture	–	4	4	103	(99)	232	133
Urban growth management							
Leveraged Loan Pool	–	7	7	–	7	474	481
Telecommunity Partnership	–	–	–	–	–	13	13
Total urban growth management	–	7	7	–	7	487	494
2003 Total	$ 217	18	235	157	78	673	751

(1) Expenditures include capital outlay of $3.

Fiduciary Funds
Agency Funds
Combining Statement of Changes in Assets and Liabilities
For the year ended September 30, 2003
(In thousands)

City of Austin, Texas
Exhibit H-3

	Balance at Beginning of Year	Additions	Deductions	Balance at End of Year
BCCP Permit Fund				
Assets				
Pooled investments and cash	$ 36	301	238	99
Total Assets	36	301	238	99
Liabilities				
Accounts payable	–	118	115	3
Due to other governments	18	48	18	48
Deposits and other liabilities	18	48	18	48
Total Liabilities	36	214	151	99
Campaign Financing Fund				
Assets				
Pooled investments and cash	37	25	1	61
Total Assets	37	25	1	61
Liabilities				
Deposits and other liabilities	37	89	65	61
Total Liabilities	37	89	65	61
Municipal Courts				
Assets				
Pooled investments and cash	1,932	10,027	10,082	1,877
Total Assets	1,932	10,027	10,082	1,877
Liabilities				
Accounts payable	160	1,257	1,369	48
Due to other governments	1,382	10,921	10,798	1,505
Deposits and other liabilities	390	463	529	324
Total Liabilities	1,932	12,641	12,696	1,877
Neighborhood Revitalization				
Assets				
Pooled investments and cash	284	7,072	7,096	260
Total Assets	284	7,072	7,096	260
Liabilities				
Deposits and other liabilities	284	394	418	260
Total Liabilities	284	394	418	260
Total Agency Funds				
Assets				
Pooled investments and cash	2,289	17,425	17,417	2,297
Total Assets	2,289	17,425	17,417	2,297
Liabilities				
Accounts payable	160	1,375	1,484	51
Due to other governments	1,400	10,969	10,816	1,553
Deposits and other liabilities	729	994	1,030	693
Total Liabilities	$ 2,289	13,338	13,330	2,297

CITY OF AUSTIN
FOUNDED 1839

SUPPLEMENTAL SCHEDULES

Enterprise Related Grants
Combining Balance Sheet
September 30, 2003
(In thousands)

City of Austin, Texas
Exhibit I-1

	Assets			Liabilities and Fund Balances				
	Pooled Investments and Cash	Receivables from Other Governments	Total Assets	Advanced Pooled Investments and Cash	Other Liabilities	Total Liabilities	Fund Balances	Total Liabilities and Fund Balances
ELECTRIC RELATED								
U.S. Department of Energy	$ 179	18	197	18	179	197	--	197
Public Utility Commission of Texas	--	167	167	167	--	167	--	167
ICLEI USA, Inc.	--	--	--	--	--	--	--	--
Total Electric	179	185	364	185	179	364	--	364
WATER AND WASTEWATER RELATED								
U.S. Environmental Protection Agency	--	--	--	--	--	--	--	--
U.S. Fish and Wildlife	--	7	7	7	--	7	--	7
Texas On-Site Wastewater Treatment Research Council	--	--	--	--	--	--	--	--
Total Water and Wastewater Related	--	7	7	7	--	7	--	7
AIRPORT RELATED								
U.S. Department of Transportation	--	1,702	1,702	1,702	--	1,702	--	1,702
Federal Bureau of Investigation	--	4	4	4	--	4	--	4
Propane Education and Research Council	--	155	155	155	--	155	--	155
Texas Comptroller of Public Accounts	8	--	8	--	8	8	--	8
Total Airport	8	1,861	1,869	1,861	8	1,869	--	1,869
DRAINAGE RELATED								
U.S. Environmental Protection Agency	--	2	2	2	--	2	--	2
Total Drainage	--	2	2	2	--	2	--	2
PRIMARY CARE								
U.S. Health and Human Services	84	326	410	326	84	410	--	410
Telecommunications Infrastructure Fund Board	--	--	--	--	--	--	--	--
Reach Out and Read National Center	4	--	4	--	4	4	--	4
Total Primary Care	88	326	414	326	88	414	--	414
SOLID WASTE								
Capital Area Planning Council	--	--	--	--	--	--	--	--
Total Solid Waste	--	--	--	--	--	--	--	--
Total grants, enterprise related	$ 275	2,381	2,656	2,381	275	2,656	--	2,656

NOTE: These grants have been reported in the enterprise fund financial statements.

Enterprise Related Grants
Combining Schedule of Expenditures
From Inception to September 30, 2003
(In thousands)

City of Austin, Texas
Exhibit I-2

	Total Expenditures at Beginning of Year			Current Year		Total Expenditures at End of Year			Budget		
	Grant	In-Kind Match	Total	Grant	In-Kind Match	Grant	In-Kind Match	Total	Grant	In-Kind Match	Total
ELECTRIC RELATED											
U.S. Department of Energy	$ 449	936	1,385	71	34	520	970	1,490	1,066	1,490	2,556
Public Utility Comission of Texas	--	--	--	167	--	167	--	167	167	--	167
ICLEI USA, Inc.	6	--	6	15	--	21	--	21	42	35	77
Total Electric	455	936	1,391	253	34	708	970	1,678	1,275	1,525	2,800
WATER AND WASTEWATER RELATED											
U.S. Environmental Protection Agency	9,832	--	9,832	115	--	9,947	--	9,947	10,115	--	10,115
U.S. Fish and Wildlife	7	--	7	6	--	13	--	13	31	8	39
Texas On-Site Wastewater Treatment Research Council	14	--	14	--	--	14	--	14	20	--	20
Total Water and Wastewater Related	9,853	--	9,853	121	--	9,974	--	9,974	10,166	8	10,174
AIRPORT RELATED											
U.S. Department of Transportation	9,420	2,998	12,418	8,292	2,121	17,712	5,119	22,831	28,727	8,057	36,784
Federal Bureau of Investigation	--	--	--	5	--	5	--	5	11	--	11
Propane Education and Research Council	--	--	--	155	--	155	--	155	300	--	300
Texas Comptroller of Public Accounts	16	--	16	2	--	18	--	18	23	--	23
Total Airport	9,436	2,998	12,434	8,454	2,121	17,890	5,119	23,009	29,061	8,057	37,118
DRAINAGE RELATED											
U.S. Environmental Protection Agency	199	--	199	11	--	210	--	210	850	--	850
Total Drainage	199	--	199	11	--	210	--	210	850	--	850
PRIMARY CARE											
U.S. Health and Human Services	884	--	884	801	--	1,685	--	1,685	2,851	--	2,851
Telecommunications Infrastructure Fund Board	148	60	208	--	--	148	60	208	600	60	660
Reach Out and Read National Center	2	--	2	--	--	2	--	2	6	--	6
Total Primary Care	1,034	60	1,094	801	--	1,835	60	1,895	3,457	60	3,517
SOLID WASTE											
Capital Area Planning Council	--	--	--	43	--	43	--	43	43	--	43
Total Solid Waste	--	--	--	43	--	43	--	43	43	--	43
Total grants, enterprise related	$ 20,977	3,994	24,971	9,683	2,155	30,660	6,149	36,809	44,852	9,650	54,502

NOTE: These grants have been reported in the enterprise fund financial statements.

Schedule of General Obligation Bonds
Authorized and Unissued
Year ended September 30, 2003
(In thousands)

City of Austin, Texas
Exhibit I-3

Date Authorized	Purpose	Original Authorized	Previously Issued (1)	Issued During Current Year	Unissued September 30, 2003
10-22-83	Brackenridge 2000	$ 50,000	40,785	--	9,215
09-08-84	Parks improvements	9,975	9,648	--	327
01-19-85	Cultural arts	20,285	14,890	--	5,395
11-03-98	Traffic signals	152,000	95,582	20,915	35,503
11-03-98	Parks and recreation facilities	75,925	40,250	14,473	21,202
11-03-98	Public safety facilities	54,675	46,170	8,505	--
11-03-98	Cultural arts and land acquisition	46,390	34,845	--	11,545
11-07-00	Street improvements	150,000	30,000	15,000	105,000
11-07-00	Land acquisition	13,400	10,000	3,400	--
		$ 572,650	322,170	62,293	188,187

Source: Bond Sale Official Statements

(1) This schedule displays only those previously issued bonds that relate to bond authorizations included herein. It does not display all debt previously issued and still outstanding or refunding bonds. It includes general obligation bonds reported in governmental and proprietary funds.

Schedule of Revenue Bonds Authorized, Deauthorized and Unissued
Year ended September 30, 2003
(In thousands)

City of Austin, Texas
Exhibit I-4

Date Authorized	Purpose	Original Authorized	Deauthorized	Previously Issued (1)	Issued During Current Year	Unissued September 30, 2003
ELECTRIC UTILITY						
10-22-83	Hydrogeneration power plant and electric system	$ 39,000	–	10,620	–	28,380
03-01-84	Electric system, South Texas Nuclear Project	605,000	–	315,232	–	289,768
09-08-84	Electric improvements (gas turbines)	32,775	–	31,237	–	1,538
09-08-84	Electric improvements (western coal plant)	47,725	–	31,199	–	16,526
09-08-84	Electric transmission and reliability improvements	39,945	–	20,040	–	19,905
12-14-85	Transmission lines and substations	175,130	–	96,017	–	79,113
12-14-85	Overhead and underground distribution	76,055	–	46,845	–	29,210
12-14-85	Miscellaneous	25,891	–	10,443	–	15,448
08-10-92	Electrical distribution and street lighting	82,500	–	–	–	82,500
Total Electric Utility		1,124,021	–	561,633	–	562,388
WATER UTILITY						
09-11-82	Green water treatment plant, water lines and reservoir	40,300	–	28,885	–	11,415
09-11-82	Ullrich water treatment plant, water lines and reservoir	49,100	–	42,210	–	6,890
09-11-82	Davis water treatment plant, water lines and reservoir	40,800	–	32,274	–	8,526
09-11-82	Waterworks system rehabilitation and improvements	12,800	–	9,164	–	3,636
09-08-84	Waterworks north central, northeast, and east service area	39,385	17,000	3,990	–	18,395
09-08-84	Waterworks northwest service area	14,970	–	11,430	–	3,540
09-08-84	Water improvements in north central and northwest service area	14,470	–	2,745	–	11,725
09-08-84	Waterworks system improvements	141,110	–	36,513	–	104,597
09-08-84	Ullrich water treatment plant improvements to South Austin	47,870	–	23,245	–	24,625
09-08-84	Water lines, reservoir improvements to south corridor area	12,570	–	6,585	–	5,985
09-08-84	Water lines, pump station improvements to North Austin area	7,945	–	7,765	–	180
09-08-84	Waterworks system rehabilitation and improvements	26,500	–	3,665	–	22,835
12-14-85	Northeast area improvements	37,950	10,000	7,493	–	20,457
12-14-85	South/southeast area improvements	42,090	14,000	6,035	–	22,055
12-14-85	Improvements/extensions	9,775	–	3,689	–	6,086
08-10-92	Improvements to meet EPA safe drinking water act	23,000	–	–	–	23,000
08-10-92	Improvements and replacement of deteriorated water system facilities	5,000	–	–	–	5,000
08-10-92	General utility relocation	2,000	–	–	–	2,000
05-03-97	Improvements/extensions to City's waterworks and wastewater system	35,000	–	–	–	35,000
05-06-98	Improvements/extensions to City's waterworks and wastewater system	65,000	–	–	–	65,000
11-03-98	Water improvements, upgrade, replace	64,900	–	–	–	64,900
11-03-98	Water expansion and improvement	49,940	–	–	–	49,940
11-03-98	Water improvements and extensions	19,800	–	–	–	19,800
Total Water Utility		$ 802,275	41,000	225,688	–	535,587

(Continued)

(1) This schedule displays only those previously issued bonds which relate to bond authorizations included herein. It does not display all debt previously issued and still outstanding, refunding bonds, or commercial paper.

Schedule of Revenue Bonds Authorized, Deauthorized and Unissued
Year ended September 30, 2003
(In thousands)

City of Austin, Texas
Exhibit I-4

(Continued)

Date Authorized	Purpose	Original Authorized	Deauthorized	Previously Issued (1)	Issued During Current Year	Unissued September 30, 2003
WASTEWATER UTILITY						
11-20-76	Sewer system improvements	$ 46,920	–	38,920	–	8,000
09-11-82	Govalle sewage treatment plant, sewer lines and improvements to Canterbury lift station	28,300	–	24,658	–	3,642
09-11-82	Onion Creek sewage treatment plant and sewer lines	57,000	–	49,345	–	7,655
09-11-82	Sewer lines for north central and northwest Austin	20,700	–	17,975	–	2,725
09-11-82	Walnut Creek sewage treatment plant additions	20,400	–	17,971	–	2,429
09-11-82	Sewer system rehabilitation and improvements	4,800	–	3,930	–	870
09-08-84	Sewer system rehabilitation and improvements	43,515	–	36,950	–	6,565
09-08-84	Onion Creek and Walnut Creek sewage treatment plant improvements	44,795	–	42,284	–	2,511
09-08-84	Sewer system rehabilitation and improvements	46,230	–	14,925	–	31,305
05-06-85	Sewer system improvements	54,000	–	33,106	–	20,894
12-14-85	Advanced wastewater treatment	34,500	–	–	–	34,500
12-14-85	Northeast area improvements	47,035	32,300	1,857	–	12,878
12-14-85	Southeast area improvements	9,200	4,200	757	–	4,243
12-14-85	Improvements/extensions	24,725	–	12,621	–	12,104
12-14-85	Walnut Creek WWTP expansion	46,000	–	13,717	–	32,283
12-14-85	Bear Creek interceptor	1,840	1,511	265	–	64
08-10-92	Improvement to Hornsby Bend beneficial re-use program	11,000	–	–	–	11,000
08-10-92	Replacement and rehabilitation of deteriorated wastewater facilities	3,000	–	–	–	3,000
11-03-98	Wastewater improvements, upgrades and replacements	77,000	–	–	–	77,000
11-03-98	Wastewater improvements and expansion	121,000	–	–	–	121,000
Total Wastewater Utility		741,960	38,011	309,281	–	394,668
Total Utility		2,668,256	79,011	1,096,602	–	1,492,643
AIRPORT						
11-03-87	Relocation/construction of new airport	728,000	–	30,000	–	698,000
05-01-93	Construction of new municipal airport at Bergstrom AFB site	400,000	–	362,205	–	37,795
Total Airport		1,128,000	–	392,205	–	735,795
CONVENTION CENTER						
07-29-89	New convention center	69,000	–	68,240	–	760
Total Convention Center		69,000	–	68,240	–	760
Total revenue bonds		$ 3,865,256	79,011	1,557,047	–	2,229,198

Source: Bond sale official statements

CITY OF AUSTIN
FOUNDED 1839

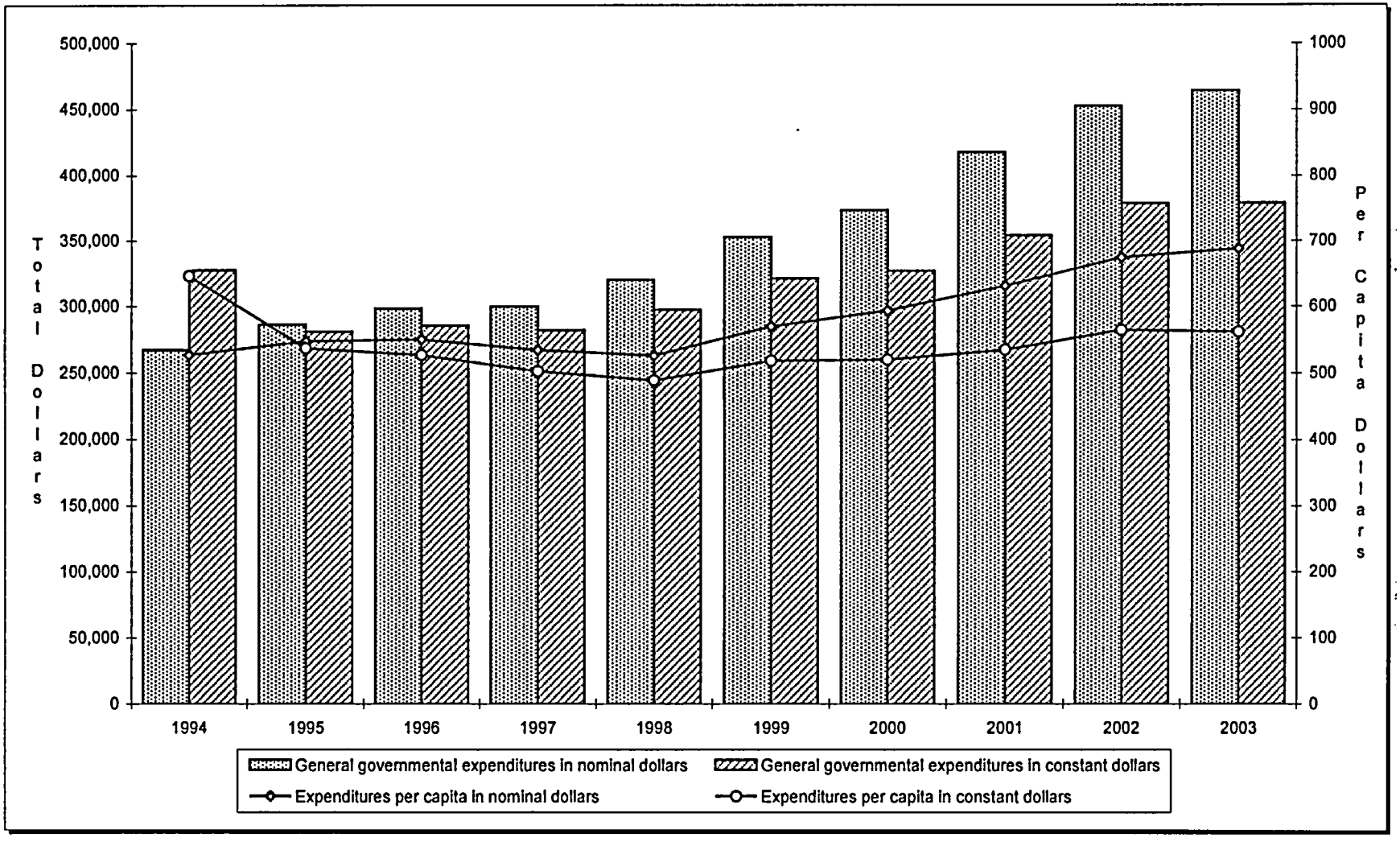
STATISTICAL SECTION - UNAUDITED

Financial presentations included in the Statistical Section provide data on the financial, physical and economic characteristics of the City. These tables cover multiple fiscal years and provide users with a broader and more complete understanding of the City and its financial affairs.

CITY OF AUSTIN
FOUNDED 1839

General Governmental Total Expenditures and Expenditures per Capita
1994-2003 (In thousands)
In nominal and constant 1994 dollars

City of Austin, Texas
Exhibit 1

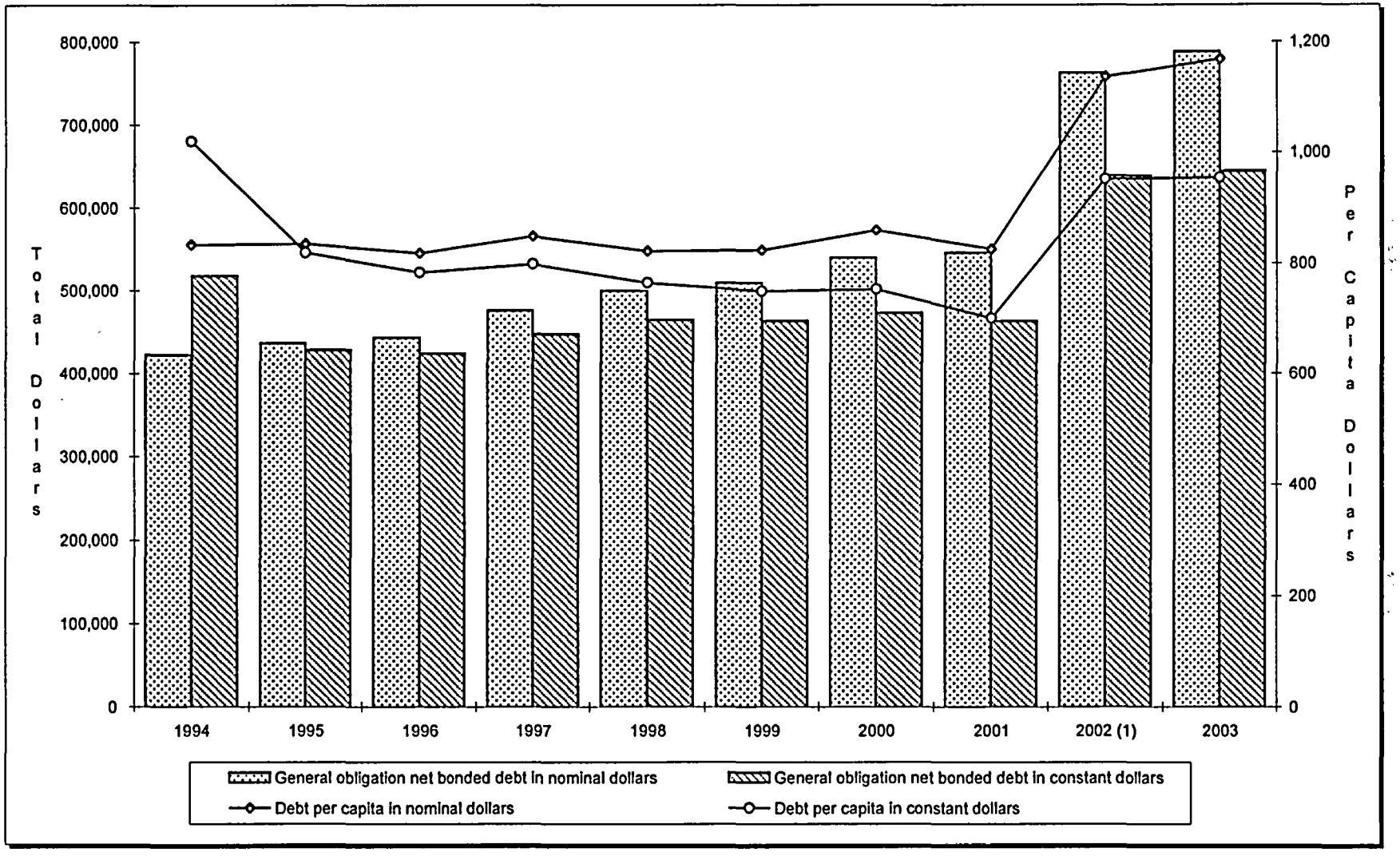


Population	507	523	542	561	608	619	629	662	671	675

Note: General governmental includes the General Fund and two internal service funds, Information Systems and Support Services.

General Obligation Net Debt and Net Debt per Capita
1994-2003 (In thousands)
In nominal and constant 1994 dollars

City of Austin, Texas
Exhibit 2

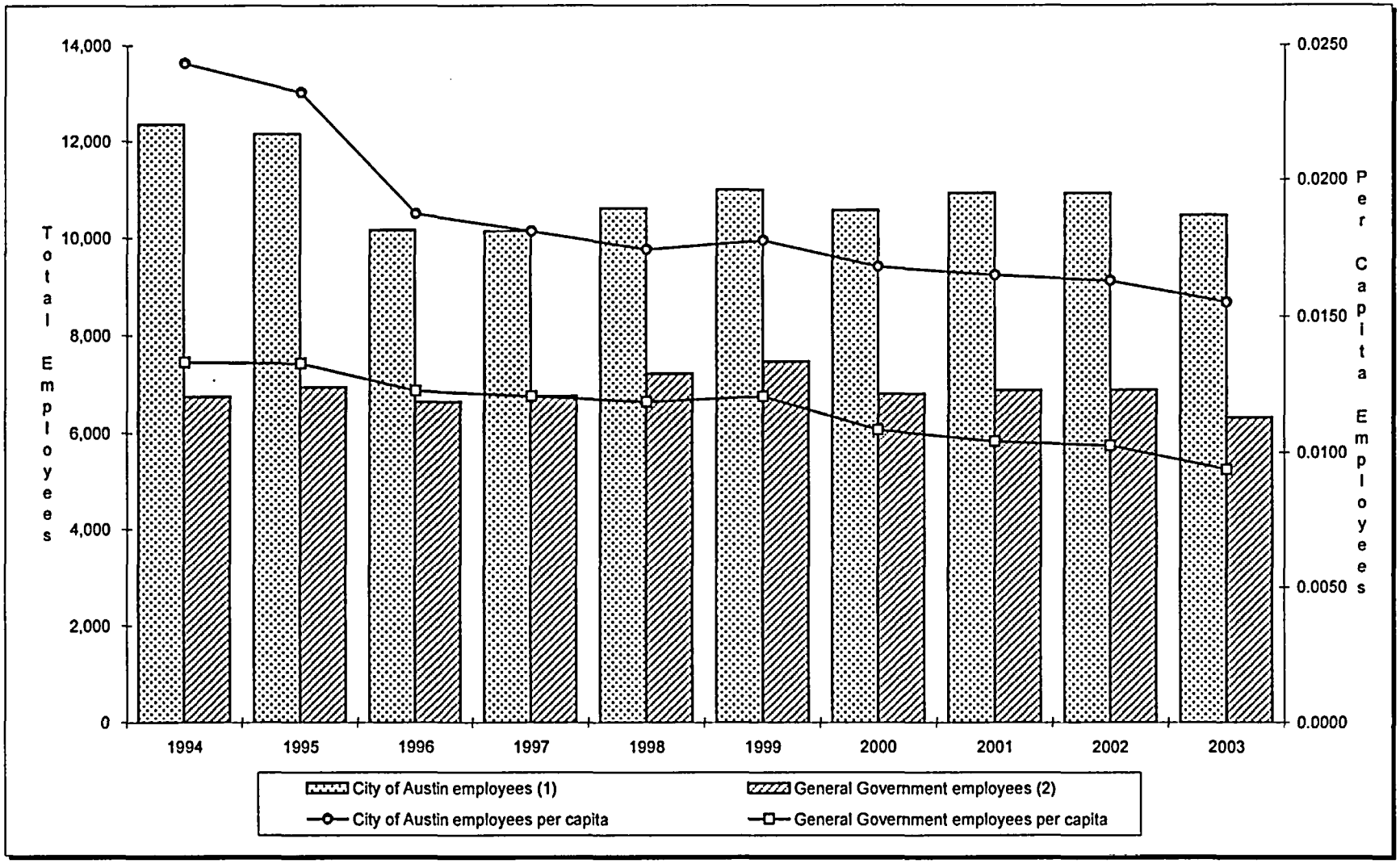


Population	507	523	542	561	608	619	629	662	671	675

(1) In 2002 changed the timing of bond issuance from October to September, resulting in two bond issuances.

City of Austin Employees per Capita
1994-2003

City of Austin, Texas
Exhibit 3



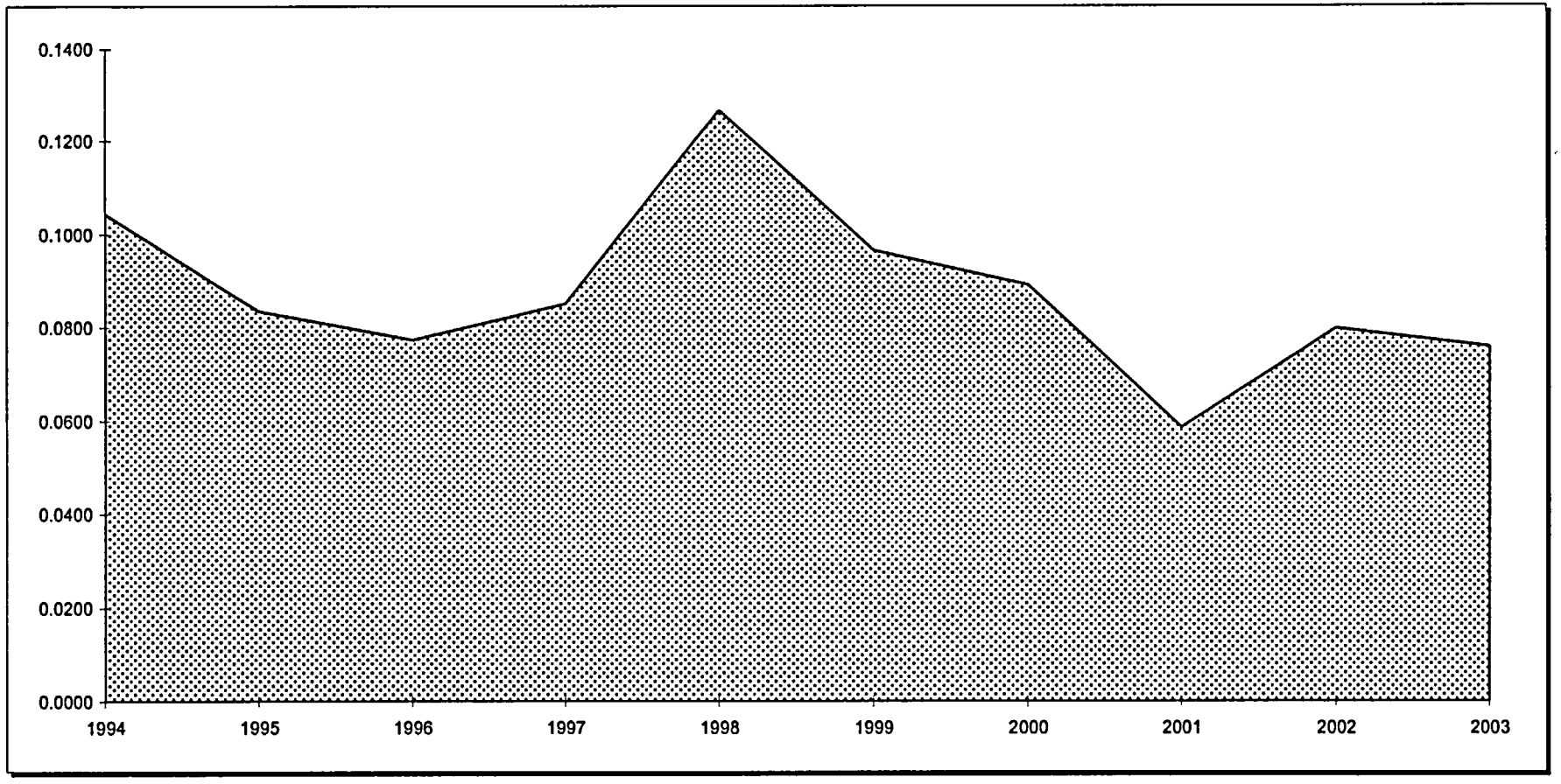
Population	507,000	523,000	542,000	561,000	608,000	619,000	629,000	662,000	671,000	675,000

(1) Includes part-time employees
(2) Includes grant-funded employees and part-time employees

Ratio of General Fund Unreserved Ending Balance to General Governmental Annual Expenditures 1994-2003 (In thousands)

City of Austin, Texas
Exhibit 4

		1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
Unreserved fund balance	$	27,903	23,929	23,083	25,501	40,502	34,029	33,243	24,457	36,078	35,196
Annual expenditures	$	267,435	286,528	298,416	299,845	319,902	352,697	373,258	417,494	452,487	464,379



Note: General governmental includes the General Fund and two internal service funds, Information Systems and Support Services.

General Governmental Expenditures by Function
1994-2003 (In thousands)

City of Austin, Texas
Table 1

EXPENDITURES BY FUNCTION

Fiscal Year Ended Sept. 30	Total (1)	Administration	Fiscal Management	Public Safety	Public Services and Utilities	Public Health		Public Recreation and Culture		Social Services Management	Support Services	Urban Growth Management	General City Responsibilities
								Parks	Libraries				
	$	$	$	$	$	$		$	$	$	$	$	$
1994	267,435	10,013	13,117	122,433	14,087	39,455	(2)	18,796	9,975	7,153	21,944	10,861	(399)
1995	286,528	9,186	12,499	131,743	15,550	40,432		19,258	10,617	7,335	20,451	11,402	8,055
1996	298,416	10,530	15,420	141,141	11,904	43,647		19,411	10,681	7,286	21,357	10,567	6,472
1997	299,845	10,661	16,250	144,288	9,676	43,190		21,283	11,481	6,739	22,513	7,501	6,263
1998	319,902	10,923	16,567	162,733	10,128	37,060		23,066	12,795	8,205	24,304	8,380	5,741
1999	352,697	13,045	19,628	173,963	11,099	40,678		26,028	14,901	8,627	29,993	9,129	5,606
2000	373,258	15,555	21,175	191,591	6,098	41,032		27,994	16,211	9,387	30,117	10,189	3,909
2001	417,494	18,152	20,779	210,281	9,520	41,437		30,369	17,091	8,071	41,076	11,569	9,149
2002	452,487	18,750	20,115	237,590	9,191	43,655		29,563	17,133	10,448	42,613	10,882	12,547
2003	464,379	18,030	21,785	254,684	9,380	46,061		28,170	17,023	9,985	38,910	11,638	8,713

(1) Total does not include transfers to other funds.
(2) In 1994, the Federally Qualified Health Center was created and certain expenditures shown previously in Public Health are now reported in another fund.
Note: General governmental includes the General Fund and two internal service funds, Information Systems and Support Services.

Reconciliation of Internal Service Fund expenses and General Fund expenditures

	Administration	Fiscal Management	Support Services	Total
Internal Service Fund expenses				
Mayor/Council	$ 490			490
Management Services	3,698			3,698
City Clerk	3,361			3,361
Public Information Office	1,572			1,572
Office of the City Auditor		1,395		1,395
Financial Services		20,390		20,390
Information Systems			22,080	22,080
Human Resources			5,776	5,776
Small and Minority Business Resources			2,926	2,926
City Attorney			6,568	6,568
Other requirements			1,560	1,560
Total Support Services Fund	$ 9,121	21,785	38,910	69,816
General Government total expenses by function				464,379
Plus budget-basis adjustment for transfers (see Exhibit E-3)				38,316
Less Internal Service Fund expenses				(69,816)
Total General Fund expenditures (see Exhibit E-2)				$ 432,879

(Continued)

EXPENDITURES BY FUNCTION AS A PERCENT OF TOTAL EXPENDITURES

Fiscal Year Ended Sept. 30	Total (1)	Administration	Fiscal Management	Public Safety	Public Services and Utilities	Public Health		Public Recreation and Culture		Social Services Management	Support Services	Urban Growth Management	General City Responsibilities
								Parks	Libraries				
	%	%	%	%	%	%		%	%	%	%	%	%
1994	100.00	3.74	4.90	45.78	5.27	14.75	(2)	7.04	3.73	2.67	8.21	4.06	-0.15
1995	100.00	3.21	4.36	45.98	5.43	14.11		6.72	3.70	2.56	7.14	3.98	2.81
1996	100.00	3.53	5.17	47.30	3.99	14.62		6.50	3.58	2.44	7.16	3.54	2.17
1997	100.00	3.56	5.42	48.11	3.23	14.40		7.10	3.83	2.25	7.51	2.50	2.09
1998	100.00	3.41	5.18	50.88	3.17	11.58		7.21	4.00	2.56	7.60	2.62	1.79
1999	100.00	3.70	5.57	49.32	3.15	11.52		7.38	4.23	2.45	8.50	2.59	1.59
2000	100.00	4.17	5.67	51.34	1.63	10.99		7.50	4.34	2.51	8.07	2.73	1.05
2001	100.00	4.35	4.98	50.37	2.28	9.93		7.27	4.09	1.93	9.84	2.77	2.19
2002	100.00	4.14	4.45	52.51	2.03	9.65		6.53	3.79	2.31	9.42	2.40	2.77
2003	100.00	3.88	4.69	54.83	2.03	9.91		6.08	3.66	2.15	8.38	2.51	1.88

(1) Total does not include transfers to other funds.
(2) In 1994, the Federally Qualified Health Center was created and certain expenditures shown previously in Public Health are now reported in another fund.
Note: General governmental includes the General Fund and two internal service funds, Information Systems and Support Services.

The table on the facing page shows by function internal service funds expenses that are included above in 2003.

General Governmental Expenditures by Function
1994-2003 (In thousands)
In constant 1994 dollars

City of Austin, Texas
Table 2

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
Administration	$ 12,267	9,011	10,081	10,028	10,155	11,870	13,626	15,390	15,691	14,718
Fiscal management	16,069	12,261	14,761	15,287	15,401	17,861	18,548	17,618	16,833	17,783
Public safety	149,983	129,236	135,112	135,731	151,287	158,302	167,826	178,289	198,827	207,901
Public services and utilities	17,258	15,254	11,395	9,102	9,416	10,100	5,342	8,072	7,691	7,657
Public health	48,333 (2)	39,662	41,783	40,628	34,454	37,016	35,942	35,133	36,533	37,600
Parks	23,026	18,891	18,582	20,021	21,444	23,684	24,522	25,749	24,740	22,995
Libraries	12,219	10,415	10,225	10,800	11,895	13,560	14,200	14,491	14,338	13,896
Social services management	8,762	7,195	6,974	6,339	7,628	7,850	8,223	6,843	8,743	8,151
Support services	26,882	20,061	20,445	21,178	22,595	27,293	26,381	34,827	35,661	31,763
Urban growth management	13,304	11,185	10,116	7,056	7,791	8,307	8,925	9,809	9,107	9,500
General city responsibilities	(489)	7,902	6,196	5,892	5,337	5,102	3,424	7,758	10,500	7,113
Total (1)	$ 327,614	281,073	285,670	282,062	297,403	320,945	326,959	353,979	378,664	379,077

(1) Total does not include transfers to other funds.
(2) In 1994, the Federally Qualified Health Center was created and certain expenditures shown previously in Public Health are now reported in another fund.
Note: General governmental includes the General Fund and two internal service funds, Information Systems and Support Services.

The table below shows by function internal service funds expenses that are included above in 2003:

Department	Administration	Fiscal Management	Supportive Services	Total
Mayor/Council	$ 410			410
Management Services	3,097			3,097
City Clerk	2,813			2,813
Public Information Office	1,316			1,316
Office of the City Auditor		1,167		1,167
Financial Services		17,063		17,063
Information Systems			18,478	18,478
Human Resources			4,834	4,834
Small and Minority Business Resources			5,496	5,496
City Attorney			2,449	2,449
Other requirements			1,305	1,305
Total Support Services Fund	$ 7,636	18,230	32,562	58,428

Note: Amounts are actual expenditures adjusted by a Consumer Price Index (CPI) based on the Texas CPI.

General Fund Revenues and Other Financing Sources by Source
1994-2003 (In thousands)

City of Austin, Texas
Table 3

REVENUES AND OTHER FINANCING SOURCES

Fiscal Year Ended Sept. 30	Total	Operating Transfers In: Utility System Funds	Operating Transfers In: Other Funds	Subtotal	Property Tax	1% City Sales Tax	Mixed Drink Tax	Franchise Fees and Gross Receipts Tax	Fines and Forfeitures	Licenses and Permits	Charges for Services/ Goods	Interest and Other
	$	$	$	$	$	$	$	$	$	$	$	$
1994	256,511	67,914	25	188,572	63,567	75,780	1,809	12,188	9,764	12,851	6,519	6,094
1995	270,534	71,111	203	199,220	66,253	80,475	1,928	12,417	10,966	13,074	8,021	6,086
1996	288,328	73,583	342	214,403	74,441	83,681	2,042	13,579	12,159	14,311	8,175	6,015
1997	298,031	71,450	256	226,325	80,529	88,150	2,187	14,987	12,570	12,888	9,427	5,587
1998	333,903	72,721	--	261,182	90,775	97,581	2,354	17,101	14,493	15,541	10,261	13,076
1999	361,115	74,204	--	286,911	106,233	106,839	2,585	19,900	16,206	17,252	11,534	6,362
2000	398,096	78,352	--	319,744	115,328	122,157	2,972	23,905	16,040	18,174	11,758	9,410
2001	429,685	85,824	459	343,402	124,931	123,218	3,407	31,646	17,000	17,631	14,985	10,584
2002	482,844	88,924	48,160	345,760	143,056	115,441	3,448	29,834	17,704	14,670	15,579	6,028
2003	452,811	92,417	--	360,394	150,378	110,454	3,466	29,175	16,966	14,737	15,403	19,815

REVENUES AND OTHER FINANCING SOURCES
AS A PERCENT OF TOTAL REVENUES AND SOURCES

Fiscal Year Ended Sept. 30	Total	Operating Transfers In: Utility System Funds	Operating Transfers In: Other Funds	Subtotal	Property Tax	1% City Sales Tax	Mixed Drink Tax	Franchise Fees and Gross Receipts Tax	Fines and Forfeitures	Licenses and Permits	Charges for Services/ Goods	Interest and Other
	%	%	%	%	%	%	%	%	%	%	%	%
1994	100.00	26.48	0.01	73.51	24.78	29.54	0.70	4.75	3.81	5.01	2.54	2.38
1995	100.00	26.29	0.08	73.63	24.49	29.75	0.71	4.59	4.05	4.83	2.96	2.25
1996	100.00	25.52	0.12	74.36	25.82	29.02	0.71	4.71	4.22	4.96	2.83	2.09
1997	100.00	23.98	0.09	75.93	27.02	29.58	0.73	5.03	4.22	4.32	3.16	1.87
1998	100.00	21.78	--	78.22	27.19	29.23	0.70	5.12	4.34	4.65	3.07	3.92
1999	100.00	20.55	--	79.45	29.41	29.59	0.72	5.51	4.49	4.78	3.19	1.76
2000	100.00	19.68	--	80.32	28.97	30.69	0.75	6.00	4.03	4.57	2.95	2.36
2001	100.00	19.97	0.11	79.92	29.07	28.68	0.79	7.37	3.96	4.10	3.49	2.46
2002	100.00	18.42	9.97	71.61	29.62	23.91	0.71	6.18	3.67	3.04	3.23	1.25
2003	100.00	20.41	--	79.59	33.21	24.39	0.77	6.44	3.75	3.25	3.40	4.38

Assessed Valuation, Estimated Market Value, Tax Rates, Tax Levies, and Tax Collections
1994-2004

City of Austin, Texas
Table 4

Fiscal Year Ended Sept. 30	Valuation Date (January 1)	Ratio of Assessed Value to Market Value	Assessed Valuation	Estimated Market Value	Percent of Growth In Market Value	Tax Rate (per $100 Valuation) General Fund	Debt Service Fund	Total
		%	$	$	%	$	$	$
1994	1993	100	18,237,532,094	18,237,532,094	7.4	0.3462	0.2763	0.6225
1995	1994	100	20,958,589,300	20,958,589,300	14.9	0.3132	0.2493	0.5625
1996	1995	100	23,303,015,047	23,303,015,047	11.2	0.3177	0.2269	0.5446
1997	1996	100	25,823,385,257	25,823,385,257	10.8	0.3117	0.2134	0.5251
1998	1997	100	27,493,058,735	27,493,058,735	6.5	0.3304	0.2097	0.5401
1999	1998	100	32,458,349,755	32,458,349,755	18.1	0.3265	0.1877	0.5142
2000	1999	100	35,602,840,326	35,602,840,326	9.7	0.3222	0.1812	0.5034
2001	2000	100	41,419,314,286	41,419,314,286	16.3	0.3011	0.1652	0.4663
2002	2001	100	47,782,873,096	47,782,873,096	15.4	0.3041	0.1556	0.4597
2003	2002	100	50,759,650,668	50,759,650,668	6.2	0.2969	0.1628	0.4597
2004 (1)	2003	100	49,216,593,057	49,216,593,057	(3.0)	0.3236	0.1692	0.4928

Fiscal Year Ended Sept. 30	Valuation Date (January 1)	Total Tax Levy (October 1)	Current Tax Collections	Percent of Levy Collected	Delinquent Tax Collections	Total Tax Collections	Percent of Total Tax Collections to Tax Levy	Outstanding Delinquent Taxes	Percent of Delinquent Taxes to Tax Levy
		$	$	%	$	$	%	$	%
1994	1993	113,528,637	112,118,783	98.76	1,491,539	113,610,322	100.07	6,660,770	5.87
1995	1994	117,892,065	116,714,522	99.00	1,292,960	118,007,482	100.10	6,554,774	5.56
1996	1995	126,908,220	125,670,964	99.03	1,124,436	126,795,400	99.91	6,497,489	5.12
1997	1996	135,598,596	134,188,550	98.96	696,317	134,884,867	99.47	6,709,208	4.95
1998	1997	148,490,010	146,707,221	98.80	844,378	147,551,599	99.37	6,945,055	4.68
1999	1998	166,900,834	165,044,814	98.89	1,137,274	166,182,088	99.57	7,317,015	4.38
2000	1999	179,224,698	177,574,166	99.08	1,385,668	178,959,834	99.85	7,532,647	4.20
2001	2000	193,138,262	191,173,307	98.98	1,191,262	192,364,569	99.60	7,318,463	3.79
2002	2001	219,657,867	217,043,867	98.81	927,864	217,971,731	99.23	7,435,974	3.39
2003	2002	233,342,114	230,629,853	98.84	1,774,736	232,404,589	99.60	7,990,337	3.42
2004 (1)	2003	242,539,370	**	**	**	**	**	**	**

** Information not yet available for tax year 2003

(1) Assessed valuation for tax year 2003 is subject to change pending additional exemptions and appeals. Accordingly, the tax levy represents an estimate.

Principal Taxpayers
September 30, 2003

City of Austin, Texas
Table 5

Taxpayer	Type of Property	January 1, 2002 Assessed Valuation	Percent of Total Assessed Valuation of $50,759,650,668
		$	%
Motorola, Inc.	Manufacturing	1,016,296,140	2.00
Advanced Micro Devices, Inc.	Manufacturing	374,255,682	0.74
IBM Corporation	Manufacturing	337,578,631	0.67
Southwestern Bell Telephone Company	Telephone Utility	308,143,824	0.61
Samsung	Manufacturing	288,031,829	0.57
Applied Materials Inc.	Manufacturing	258,424,206	0.51
Minnesota Mining & Manufacturing	Manufacturing	165,254,000	0.32
State Street Bank & Trust Co	Commercial	153,091,312	0.30
Prudential Insurance Company	Commercial	147,707,585	0.29
Dell Computer Corp	Manufacturing	146,993,214	0.29
		3,195,776,423	6.30

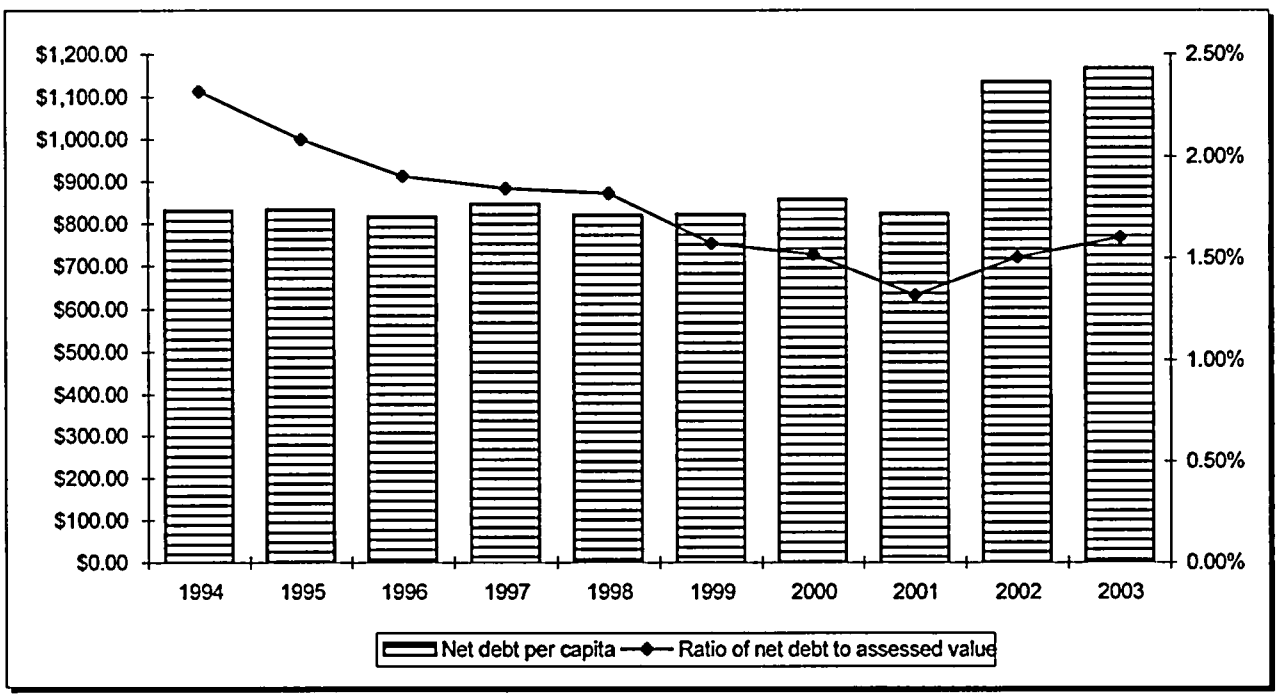
Source: Travis Central Appraisal District
Williamson County Appraisal District

Ratio of Net General Bonded Debt to Assessed Value and Net Bonded Debt per Capita
1994-2003

City of Austin, Texas
Table 6

Fiscal Year Ended Sept. 30	Population Estimate	Assessed Value	Gross Bonded Debt (1) (in 000's)	Amount Available in Debt Service Fund (2) (in 000's)	Net Bonded Debt (in 000's)	Ratio of Net Bonded Debt to Assessed Value	Ratio of Net Bonded Debt to Market Value	Net Debt Per Capita	
		$	$	$	$	%	%	$	
1994	507,468	18,237,532,094	429,261	6,523	422,738	2.32	2.32	833.03	
1995	523,352	20,958,589,300	445,803	8,935	436,868	2.08	2.08	834.75	
1996	541,889	23,303,015,047	451,722	8,475	443,247	1.90	1.90	817.97	
1997	560,939	25,823,385,257	483,677	7,529	476,148	1.84	1.84	848.84	
1998	608,214	27,493,058,735	507,297	7,270	500,027	1.82	1.82	822.12	
1999	619,038	32,458,349,755	517,629	7,870	509,759	1.57	1.57	823.47	
2000	628,667	35,602,840,326	550,039	9,756	540,283	1.52	1.52	859.41	
2001	661,639	41,419,314,286	562,678	16,467	546,211	1.32	1.32	825.54	
2002	671,044	50,759,650,668	779,075	16,451	762,624	1.50	1.50	1,136.47	(3)
2003	674,719	49,216,593,057	805,677	17,311	788,366	1.60	1.60	1,168.44	

(1) Excludes general obligation bonds, public property finance contractual obligations, and certificates of obligation issued for proprietary funds. Excludes revenue bonds and advances from other funds.
(2) Excludes loan fund balances.
(3) In 2002 changed the timing of bond issuance from October to September, resulting in two bond issuances.

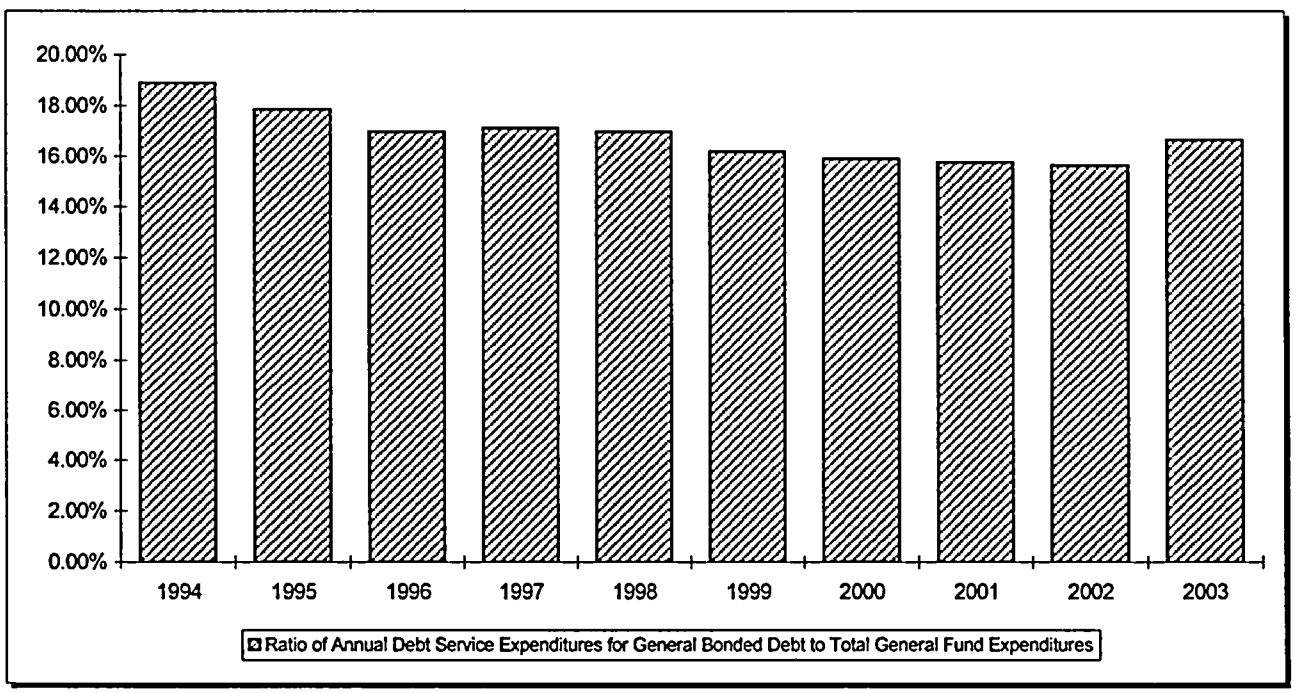


Ratio of Annual Debt Service Expenditures for General Bonded Debt to Total General Fund Expenditures
1994-2003 (in thousands)

City of Austin, Texas
Table 7

Fiscal Year Ended Sept. 30	Principal (2) (3)	Interest and Paying Agents' Commissions (2) (3)	Total Debt Service	Total General Fund Expenditures	Total Debt Service plus Total General Fund Expenditures	Ratio of Debt Service to Total (1)
	$	$	$	$	$	%
1994	28,330	24,605	52,935	227,411	280,346	18.88
1995	22,023	32,214	54,237	249,615	303,852	17.85
1996	22,723	35,039	57,762	282,773	340,535	16.96
1997	21,502	38,481	59,983	290,578	350,561	17.11
1998	22,570	40,751	63,321	310,195	373,516	16.95
1999	23,781	42,130	65,911	341,417	407,328	16.18
2000	26,920	42,094	69,014	364,938	433,952	15.90
2001	44,070	29,854	73,924	395,621	469,545	15.74
2002	43,867	35,797	79,664	430,237	509,901	15.62
2003	48,785	37,573	86,358	432,879	519,237	16.63

(1) Ratio of total debt service to total debt service plus total General Fund.
(2) Excludes payments for enterprise fund general obligation debt.
(3) Subsequent to 1999, excludes loan principal and interest.



Computation of Legal Debt Margin
September 30, 2003 (in thousands)

City of Austin, Texas
Table 8

Assessed value (100% of estimated market value) as of January 1, 2002		$ 50,759,651
Debt limit		$ 7,101,605
Amount of debt applicable to debt limit:		
Total general obligation bonds, contractual obligations, and certificates of obligation excluding proprietary fund balances of $84,551	$ 805,677	
Less: Amount available in Debt Service Fund	17,311	
Debt applicable to debt limit, excluding loan fund balances and advances from other funds		788,366
Legal debt margin		$ 6,313,239

Note - Ad valorem tax limitations: The City is permitted by Article II, Section 5 of the State of Texas Constitution to levy taxes up to $2.50 per $100 of assessed valuation for general governmental services, including payment of principal and interest on general obligation long-term debt. However, under the City Charter, a limitation on taxes levied for general governmental services, exclusive of payments of principal and interest on general obligation long-term debt, has been established at $1.00 per $100 of assessed valuation. A practical limitation on taxes levied for debt service of $1.50 per $100 of assessed valuation is established by referring to the State Statute and City Charter limitations.

Assuming the maximum tax rate for debt service of $1.50 on January 1, 2002 and assessed valuation of $50,759,651 at 95% collection, tax revenues of $723,325 would be produced. This revenue could service the debt on $7,101,605 issued as 8% - 20 year serial bonds with level debt service payments.

Computation of Direct and Overlapping Debt
September 30, 2003

City of Austin, Texas
Table 9

Name of Governmental Unit	Net Debt Outstanding as of September 30, 2003 (In 000's)	Percent Applicable to City of Austin (2)	Amount Applicable to City of Austin (In 000's)
	$	%	$
City of Austin	805,677 (1)	100.00	805,677
Greater than 10%			
Austin Community College	128,760	81.70	105,197
Austin Independent School District	444,015	79.12	351,305
North Austin MUD #1	11,392	100.00	11,392
Northwest Austin MUD #1	12,727	100.00	12,727
Northwest Travis County RD #3	5,355	100.00	5,355
Travis County	479,377	72.00	345,151
Subtotal greater than 10%	1,081,626		831,127
Less than 10%			
Del Valle Independent School District	94,070	3.12	2,935
Eanes Independent School District	110,422	3.98	4,395
Leander Independent School District	556,601	1.17	6,512
Manor Independent School District	32,664	1.72	562
Pflugerville Independent School District	222,872	4.01	8,937
Round Rock Independent School District	465,740	5.75	26,780
Williamson County	376,880	2.93	11,043
Subtotal less than 10%	1,859,249		61,164
Total direct and overlapping debt	3,746,552		1,697,968
Ratio of total direct and overlapping debt to assessed valuation (3)		3.32 %	
Per capita overlapping debt (4)		$ 2,516.56	

(1) Excludes general obligation debt reported in proprietary funds
(2) Source: Taxing jurisdictions
(3) Based on assessed valuation of $51,174,017,303
(4) Based on 2003 estimated population of 674,719

Property Tax Rates and Tax Levies
for Direct and Overlapping Governments with Applicable Percentages Over 10%
1994-2003

City of Austin, Texas
Table 10

	Tax Rates (per $100 Assessed Value) for Fiscal Year Ended September 30									
Government	**2003**	**2002**	**2001**	**2000**	**1999**	**1998**	**1997**	**1996**	**1995**	**1994**
	$	$	$	$	$	$	$	$	$	$
City of Austin	0.4597	0.4597	0.4663	0.5034	0.5142	0.5401	0.5251	0.5446	0.5625	0.6225
Austin Community College	0.0500	0.0500	0.0500	0.0500	0.0500	0.0500	0.0500	0.0482	0.0466	0.0482
Austin Independent School District	1.5964	1.5486	1.5486	1.5486	1.4319	1.4010	1.3110	1.2832	1.3450	1.4623
North Austin MUD #1	0.5000	0.5100	0.5500	0.5803	0.7100	0.7100	0.7500	--	--	--
Northwest Austin MUD #1	0.2632	0.3150	0.3577	0.3620	0.3620	0.4000	0.3926	0.3926	0.4000	0.3800
Northwest Travis County RD #3	0.1500	0.1646	0.1600	0.2248	0.2500	0.2700	0.3500	0.3541	0.4500	0.7500
Travis County (1)	0.4660	0.4460	0.4670	0.4988	0.5143	0.4938	0.4950	0.5186	0.5552	0.5966

	Tax Levies (In 000's) for Fiscal Year Ended September 30									
Government	**2003**	**2002**	**2001**	**2000**	**1999**	**1998**	**1997**	**1996**	**1995**	**1994**
	$	$	$	$	$	$	$	$	$	$
City of Austin	233,342	219,658	193,138	179,225	166,901	148,490	135,599	126,908	117,892	113,529
Austin Community College	24,863	23,323	20,571	19,209	15,255	13,971	13,900	11,951	9,458	8,641
Austin Independent School District	644,948	593,189	525,477	455,559	385,064	348,753	321,567	277,255	272,094	251,813
North Austin MUD #1	2,808	2,856	2,855	2,375	2,372	2,372	2,390	--	--	--
Northwest Austin MUD #1	874	1,093	1,046	136	659	645	125	509	434	323
Northwest Travis County RD #3	625,575	654	590	670	607	539	576	428	388	343
Travis County (1)	287,478	256,710	231,415	209,688	196,160	168,089	157,852	149,801	143,659	135,027

Note: Initial tax levies were as follows: Austin Community College - 1988, Northwest Travis County RD#3 - 1990, and Northwest Austin MUD #1 - 1989.

(1) Includes taxes and levies for Travis County and Farm to Market Roads.

Source: Travis Central Appraisal District and taxing entity.

City Sales Tax
Tax Levied Effective January 1, 1968 (Base Year is 1969)
1968-2003

City of Austin, Texas
Table 11

Fiscal Year Ended Sept. 30	(In thousands) 1st Quarter Oct. - Dec.	2nd Quarter Jan. - Mar.	3rd Quarter Apr. - Jun.	4th Quarter Jul. - Sept.	Total	Percent Base Year	Annual Percent Increase (Decrease)	Percent of Property Tax Levy	Equivalent Tax Rate
	$	$	$	$	$	%	%	%	¢
1968 (1)	--	--	--	1,458	1,458	N/A	N/A	14.58	19.54
1969	876	906	852	917	3,551	100.0	0.0	34.07	43.96
1970	974	1,089	951	1,041	4,055	114.2	14.2	35.08	45.25
1971	1,129	1,245	1,137	1,235	4,746	133.7	17.0	34.41	44.39
1972	1,309	1,465	1,339	1,415	5,528	155.7	16.5	35.50	45.80
1973	1,569	1,715	1,592	1,692	6,568	185.0	18.8	38.37	48.73
1974	1,730	1,946	1,695	1,888	7,259	204.4	10.5	38.45	48.82
1975	1,961	1,972	2,328	1,644	7,905	222.6	8.9	36.05	42.89
1976	2,242	2,318	2,046	2,560	9,166	258.1	16.0	36.17	45.94
1977	1,798	3,173	2,653	3,867	11,491	323.6	25.4	35.92	45.62
1978	3,022	3,501	3,155	3,853	13,531	381.0	17.8	40.00	49.60
1979	3,815	3,909	3,487	4,067	15,278	430.2	12.9	45.75	43.92
1980	3,793	4,269	3,722	6,000	17,784	500.8	16.4	49.42	47.44
1981	3,792	5,652	5,034	7,103	21,581	607.7	21.4	56.20	32.03
1982	4,483	6,284	5,625	8,025	24,417	687.6	13.1	53.86	33.39
1983	5,171	7,089	6,785	9,052	28,097	791.2	15.1	53.02	29.81
1984	6,331	8,823	8,963	12,756	36,873	1038.4	31.2	57.00	37.05
1985	7,917	11,289	10,922	14,506	44,634	1256.9	21.0	61.53	28.98
1986	8,379	11,394	10,435	13,741	43,949	1237.7	(1.5)	49.24	26.00
1987	7,669	10,353	9,677	12,189	39,888	1123.3	(9.2)	35.23	17.01
1988	7,318	10,596	10,651	14,360	42,925	1208.8	7.6	37.92	20.16
1989	8,039	9,427	14,140	15,566	47,172	1328.4	9.9	46.43	24.61
1990	12,381	13,277	8,918	16,964	51,540	1451.4	9.3	50.46	29.01
1991	12,762	10,539	13,578	18,522	55,401	1560.2	7.5	56.59	32.23
1992	9,304	14,713	14,231	20,007	58,255	1640.5	5.2	57.11	34.42
1993	10,869	17,393	15,971	22,821	67,054	1888.3	15.1	61.62	39.50
1994	11,897	19,225	18,072	26,586	75,780	2134.0	13.0	66.75	41.55
1995	13,198	21,628	18,836	26,813	80,475	2266.3	6.2	68.26	38.40
1996	5,643	22,056	20,294	35,688	83,681	2356.5	4.0	65.94	35.91
1997	5,571	23,258	20,850	38,471	88,150	2482.4	5.3	65.01	34.14
1998	8,335	23,188	24,054	42,004	97,581	2748.0	10.7	65.72	35.50
1999	14,684	20,637	26,051	45,467	106,839	3008.7	9.5	64.01	32.91
2000	10,389	30,780	29,300	51,688	122,157	3440.1	14.3	68.16	34.31
2001	11,325	30,977	30,574	50,342	123,218	3470.0	0.9	63.80	29.75
2002	7,887	24,060	36,417	47,077	115,441	3250.9	(6.3)	52.55	24.16
2003	9,895	27,625	27,201	45,733	110,454	3110.5	(4.3)	47.34	21.76

(1) 1% City sales tax levied effective January 1, 1968. This tax is collected and remitted to the City by the State Comptroller.

ELECTRIC FUND

Distribution –

2,360	miles primary overhead distribution lines (12KV)
3,172	miles secondary overhead distribution lines (12KV)
2,284	miles primary underground distribution lines (12KV)
2,233	miles secondary underground distribution lines (12KV)
35	miles transmission lines (69KV)
297	miles transmission lines (138KV)
269	miles transmission lines (345KV) (counting 50% of jointly owned lines with LCRA)

WATER AND WASTEWATER FUND

Source of supply – 150 mile long network of lakes created along the Colorado River by six dams with a combined storage capacity in excess of 3,300,000 acre-feet of water.

Water treatment plants	3	
Rated peak daily capacity	260,000,000	gallons
Average daily consumption	119,020,000	gallons
Average daily consumption per capita	155	gallons (based on 2003 service area population)
Water distribution –	2,995	miles of mains
	45	booster pump stations
Water connections –	184,659	metered services
	27,647	fire hydrants
Wastewater treatment plants	9	(includes 6 package treatment plants)
Combined daily capacity	130,000,000	gallons
Average daily volume	87,165,000	gallons
Collection Sanitary sewer mains	2,311	miles
Connections	169,330	
Lift stations	105	

Electric Fund and
Water and Wastewater Fund
Five-Year Comparative Operating Schedule
1999-2003 (in thousands)

City of Austin, Texas
Table 13

	Fiscal Year Ended September 30				
	2003	**2002**	**2001**	**2000**	**1999**
	$	$	$	$	$
REVENUE					
Electric					
Service Area Sales	838,189	668,744	756,246	723,260	622,489
Sales to other utilities (including capacity contract)	51,168	41,625	33,135	50,780	51,566
Rent from electric property	1,455	2,002	995	851	878
Customers' forfeited discounts and penalties	3,893	4,738	(36)	1,558	3,964
Miscellaneous	26,944	27,986	15,970	6,280	3,190
Total electric	921,649	745,095	806,310	782,729	682,087
Water					
Urban	111,689	104,547	99,156	109,963	91,861
Rural	7,293	6,837	6,439	7,413	5,582
City utility departments	–	–	–	–	310
City general government departments	–	–	–	(42)	1,087
Sales to other water utilities	7,697	7,164	7,185	7,877	6,333
Water connections	403	300	237	208	233
Customers' forfeited discounts and penalties	623	784	(5)	263	605
Miscellaneous	2,719	2,403	1,661	4,507	3,610
Total water	130,424	122,035	114,673	130,189	109,621
Wastewater					
Urban	97,495	92,793	92,328	97,895	91,672
Rural	3,971	3,311	2,810	2,631	2,229
City utility departments	–	–	1	7	546
City general government departments	–	–	–	–	42
Sales to other sewer utilities	2,966	2,983	3,161	3,114	2,858
Sewer connections	369	275	217	190	216
Customers' forfeited discounts and penalties	598	733	(3)	260	573
Industrial waste surcharge	3,846	3,662	3,730	4,041	3,950
Miscellaneous	2,696	3,742	2,998	2,152	2,335
Total wastewater	111,941	107,499	105,242	110,290	104,421
Interest	25,658	48,359	61,316	47,350	30,561
Total operating and interest revenues	1,189,672	1,022,988	1,087,541	1,070,558	926,690

(continued)

Electric Fund and
Water and Wastewater Fund
Five-Year Comparative Operating Schedule
1999-2003 (in thousands)

City of Austin, Texas
Table 13
(Continued)

	Fiscal Year Ended September 30				
	2003	**2002**	**2001**	**2000**	**1999**
	$	$	$	$	$
EXPENSE					
Electric					
Total electric	554,235	401,439	458,686	420,075	342,914
Water					
Purification	16,834	16,702	15,303	14,225	12,650
Distribution	20,796	20,897	20,197	18,247	15,575
Customer accounting and collection	6,035	6,378	5,202	5,457	3,908
Jobbing and contract work	(118)	(78)	52	14	(27)
Design engineering	708	800	425	1,922	1,251
Administrative and general	14,754	15,296	12,406	12,939	10,764
Total water	59,009	59,995	53,585	52,804	44,121
Wastewater					
Sewer lines	5,609	6,299	6,175	7,592	8,563
Sewage treatment plant	20,913	21,405	19,172	17,115	17,634
Customer accounting and collection	2,911	3,017	4,374	4,406	2,483
Jobbing and contract work	11	24	87	69	56
Design engineering	7,396	7,437	6,846	1,998	2,312
Administrative and general	13,567	14,164	12,172	12,382	11,842
Total wastewater	50,407	52,346	48,826	43,562	42,890
Total expenses (1)	663,651	513,780	561,097	516,441	429,925
Net revenue available for debt service	526,021	509,208	526,444	554,117	496,765

(1) Interest expense, depreciation, amortization and other nonoperating items are not included in total expense.

Electric Fund and
Water and Wastewater Fund
Plant Cost and Equity in Utility Systems
1999-2003 (in thousands)

City of Austin, Texas
Table 14

	Fiscal Year Ended September 30				
	2003	2002	2001	2000	1999
	$	$	$	$	$
PLANT COST					
Utility systems					
Electric	3,399,284	3,231,331	3,067,650	2,842,927	2,693,238
Water	1,275,501	1,220,643	1,169,575	1,090,912	1,003,650
Wastewater	1,214,498	1,123,646	1,080,759	1,032,885	976,681
Total cost	5,889,283	5,575,620	5,317,984	4,966,724	4,673,569
Allowance for depreciation:					
Electric	1,288,675	1,203,986	1,131,861	1,048,947	972,368
Water	299,550	278,757	264,352	242,395	220,478
Wastewater	358,634	337,795	328,640	304,152	280,009
Total depreciation	1,946,859	1,820,538	1,724,853	1,595,494	1,472,855
Cost after depreciation	3,942,424	3,755,082	3,593,131	3,371,230	3,200,714
EQUITY IN UTILITY SYSTEMS					
Utility systems	5,889,283	5,575,620	5,317,983	4,966,724	4,673,569
Plus:					
Inventories, materials and supplies (1)	32,349	32,980	34,689	32,905	32,227
Net construction assets and unamortized bond issue cost (2)	28,922	125,858	154,576	126,423	145,028
	5,950,554	5,734,458	5,507,248	5,126,052	4,850,824
Less:					
Allowance for depreciation	1,946,859	1,820,538	1,724,853	1,595,495	1,472,854
Construction contracts payable	–	–	279	1,149	2,128
	1,946,859	1,820,538	1,725,132	1,596,644	1,474,982
Utility systems, net	4,003,695	3,913,920	3,782,116	3,529,408	3,375,842
Revenue bonds and other debt outstanding (3)	2,798,156	2,796,408	2,779,856	2,722,323	2,651,729
Less:					
Bond retirement and reserve funds	144,410	147,637	170,700	161,597	160,867
Net debt	2,653,746	2,648,771	2,609,156	2,560,726	2,490,862
Equity in utility systems	1,349,949	1,265,149	1,172,960	968,682	884,980
Percentage of equity in utility systems	33.72%	32.32%	31.01%	27.45%	26.22%

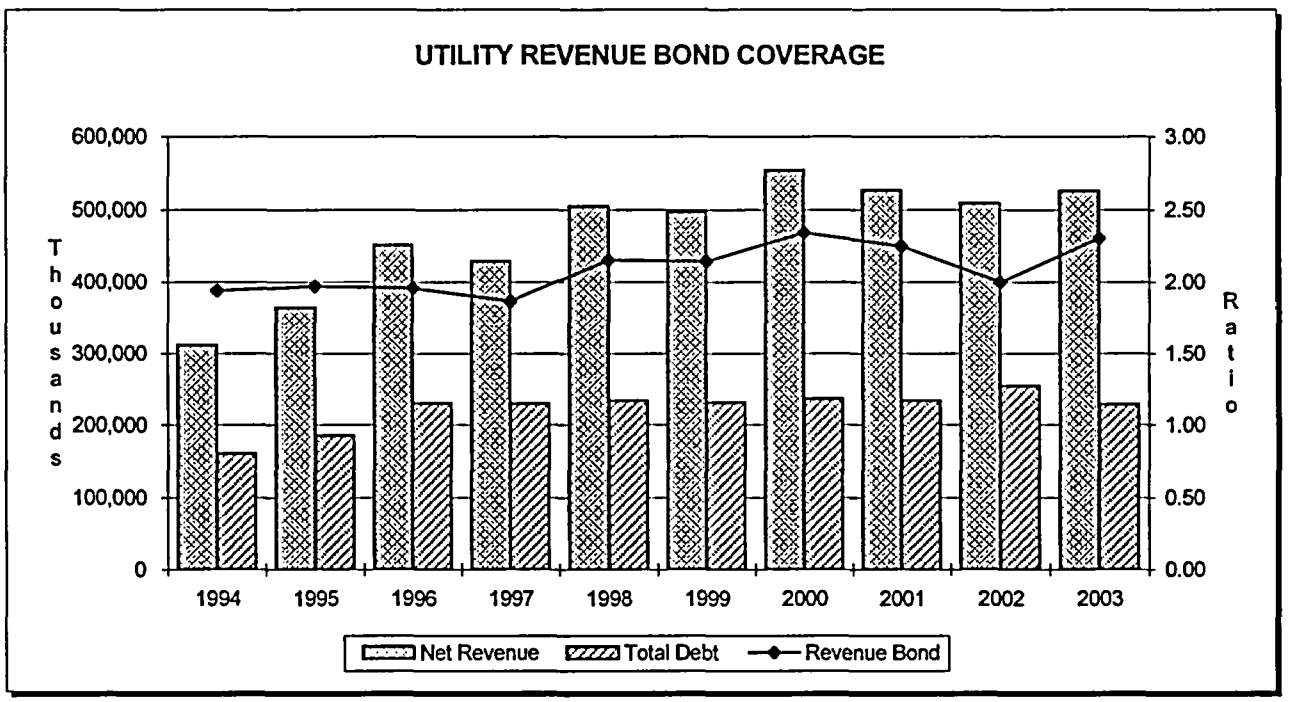
(1) Does not include fuel oil or coal inventories of approximately $14.2 million at September 30, 2003. Consists primarily of spare parts inventory at Fayette Plant and South Texas Project.
(2) Includes investment in municipal utility districts of $2 thousand.
(3) Includes Revenue Bonds and Tax/Revenue Bonds of $2,622.1 million (net of discounts, unamortized gains and losses on refundings, and inclusive of premiums); Contract Revenue Bonds of $16.2 million; Capital Lease Obligations of $14.9 million; Commercial Paper of $128.4 million (net of discounts); General Obligation Bonds of $8.8 million; and Contractual Obligation Bonds of $7.6 million.

Schedule of Combined Utility Systems
Electric Fund and Water and Wastewater Fund
Revenue Bond Coverage
1994-2003 (in thousands)

City of Texas, Austin
Table 15

Fiscal Year Ended Sept. 30	Net Revenue Available for Debt Service: Total Revenue (1)	Net Revenue Available for Debt Service: Operating Expenses (2)	Net Revenue Available for Debt Service: Net Revenue Available for Debt Service	Debt Service Requirements (3): Principal	Debt Service Requirements (3): Interest	Debt Service Requirements (3): Total Debt Service	Revenue Bond Coverage (4)
	$	$	$	$	$	$	$
1994	684,560	372,995	311,565	14,885	145,845	160,730	1.94
1995	717,231	352,003	365,228	34,547	150,952	185,499	1.97
1996	831,371	380,407	450,964	75,520	154,728	230,248	1.96
1997	812,186	383,121	429,065	82,541	146,998	229,539	1.87
1998	918,508	413,939	504,569	93,922	140,541	234,463	2.15
1999	926,692	429,926	496,766	100,084	131,627	231,711	2.14
2000	1,070,558	516,441	554,117	96,790	140,126	236,916	2.34
2001	1,087,541	561,097	526,444	101,357	133,055	234,412	2.25
2002	1,022,988	513,780	509,208	98,876	155,645	254,521	2.00
2003	1,189,672	663,651	526,021	86,825	141,722	228,547	2.30

(1) Operating revenue and interest income.
(2) Operating expenses other than interest on debt, depreciation and amortization.
(3) Debt service calculations are done on a cash basis rather than the accrual basis used in preparation of the financial statements.
(4) Revenue bond coverage is equal to net revenue available for debt service divided by total principal and interest payments made during each fiscal year. Coverage includes prior, subordinate, and separate lien bonds only.



Transfers from Electric Fund and
Water and Wastewater Fund
to General Fund
1983-2003 (in thousands)

City of Austin, Texas
Table 16

Fiscal Year	Operating Revenue	Other Revenue	Total Revenue	Transfers To General Fund	Percentage of Total Revenue
	$	$	$	$	%
1983	364,544	24,715	389,259	40,836	10.49
1984	451,146	31,331	482,477	46,057	9.55
1985	447,699	42,190	489,889	50,525	10.31
1986	516,724	51,724	568,448	56,090	9.87
1987	525,350	56,138	581,488	60,203	10.35
1988	556,356	42,873	599,229	63,741	10.64
1989	542,516	50,231	592,747	64,460	10.87
1990	585,184	53,748	638,932	63,666	9.96
1991	571,816	42,875	614,691	63,055	10.26
1992	578,276	31,038	609,314	73,238	12.02
1993	645,075	25,202	670,277	68,582	10.23
1994	662,807	21,753	684,560	67,914	9.92
1995	690,832	26,400	717,232	71,111	9.91
1996	800,078	31,293	831,371	73,583	8.85
1997	774,262	37,924	812,186	71,450	8.80
1998	870,163	48,345	918,508	72,721	7.92
1999	896,130	30,561	926,691	74,204	8.01
2000	1,023,208	47,351	1,070,559	78,352	7.32
2001	1,026,225	61,316	1,087,541	85,824	7.89
2002	974,629	48,359	1,022,988	88,924	8.69
2003	1,164,014	25,658	1,189,672	92,417	7.77

Electric Fund and
Water and Wastewater Fund
Statistical Data
Year ended September 30, 2003
With comparative totals for year ended September 30, 2002

City of Austin, Texas
Table 17

	Electric Sales (KWH)		Number of Metered Customers (average)	
	2003	2002	2003	2002
Electric:				
Totals	10,321,397,755	10,152,740,460	359,526	353,072

KWH and number of customers do not include Sale for Resale information.

	2003		2002	
	Average Customers	Thousand Gallons	Average Customers	Thousand Gallons
Water and Wastewater:				
Thousands of gallons pumped		51,110,847 (1)		50,883,130 (1)
Less: Sales to other utilities		3,437,043		3,476,482
Thousand gallons to system		47,673,804		47,406,648
Water sales:				
Urban	169,839	35,644,803	167,895	36,577,034
Rural	13,512	2,302,234	12,899	2,338,585
	183,351	37,947,037	180,794	38,915,619
City departments	387	553,582	387	616,775
	183,738	38,500,619	181,181	39,532,394
Used by utility		1,506,146		1,529,717
Other unmetered usage		3,460,215		3,448,000
Loss and unaccounted for		4,206,824		2,896,537
Thousand gallons to system		47,673,804		47,406,648
Maximum daily use		224,592		206,125
Average daily consumption		119,024		122,024

(1) Pumpage includes the Davenport WTP estimate provided by ST Environmental Services.

Water and Wastewater Fund
Large Customers
Five-Year Comparative Data (1999-2003)

City of Austin, Texas
Table 18

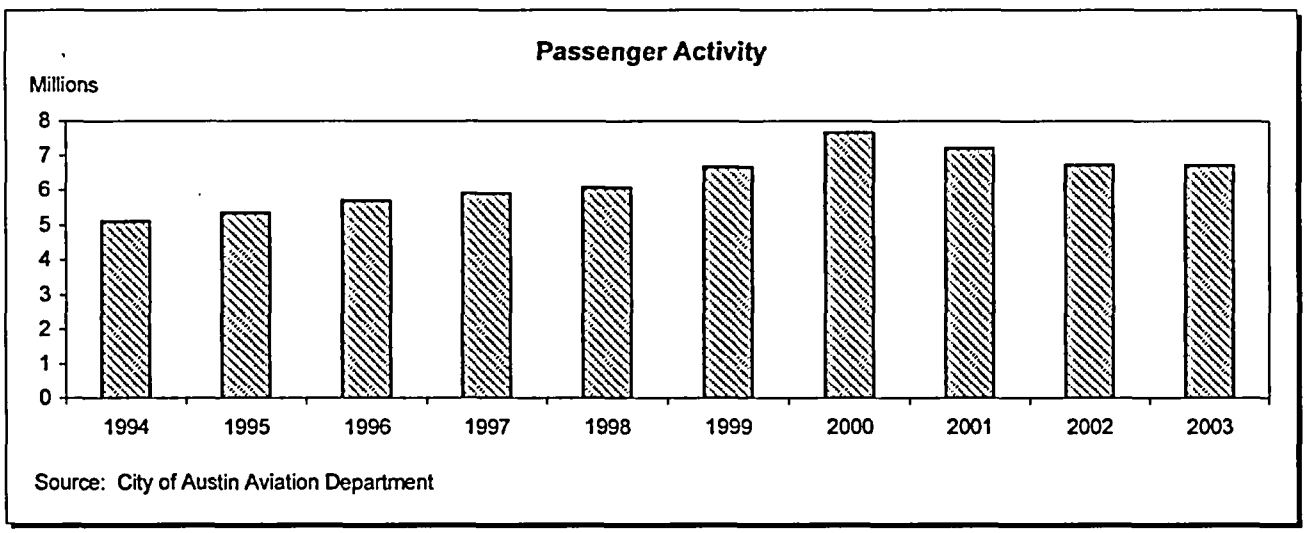
	Fiscal Year Ended September 30 (dollars in thousands)									
	2003		2002		2001		2000		1999	
	Gallons	Revenue	Gallons	Revenue	Gallons	Revenue	Gallons	Revenue	Gallons	Revenue
		$		$		$		$		$
LARGE WATER CUSTOMERS										
Motorola, Inc. (1)	1,048,571	2,654	1,277,560	3,202	1,931,463	4,886	1,814,060	4,031	1,781,016	3,855
The University of Texas at Austin	962,813	2,563	863,720	2,319	1,135,801	4,094	1,029,359	2,341	908,424	2,056
Water District 10	795,059	1,646	773,882	1,604	848,672	1,666	901,248	1,831	699,180	1,416
Advanced Micro Devices	792,393	2,009	911,042	2,291	979,919	2,340	1,044,510	2,082	1,186,752	2,570
Wells Branch MUD	563,339	1,090	575,113	1,092	587,057	1,076	646,054	1,328	544,046	1,107
Anderson Mill MUD	486,171	949	477,297	757	486,185	851	546,213	936	510,713	872
Samsung	485,945	1,229	495,548	1,246	492,533	1,153	462,139	1,005	353,927	768
North Austin MUD	354,291	718	367,626	910	364,580	712	406,345	850	297,789	622
Lost Creek	304,709	655	293,571	612	303,592	608	355,547	758	282,637	600
Shady Hollow MUD	237,135	567	224,608	523	247,103	496	300,277	800	217,346	576
	6,030,426	14,080	6,259,967	14,556	7,376,905	17,882	7,505,752	15,962	6,781,830	14,442

(1) Totals for Motorola, Inc. include the east Austin plant site and the west Austin plant site.

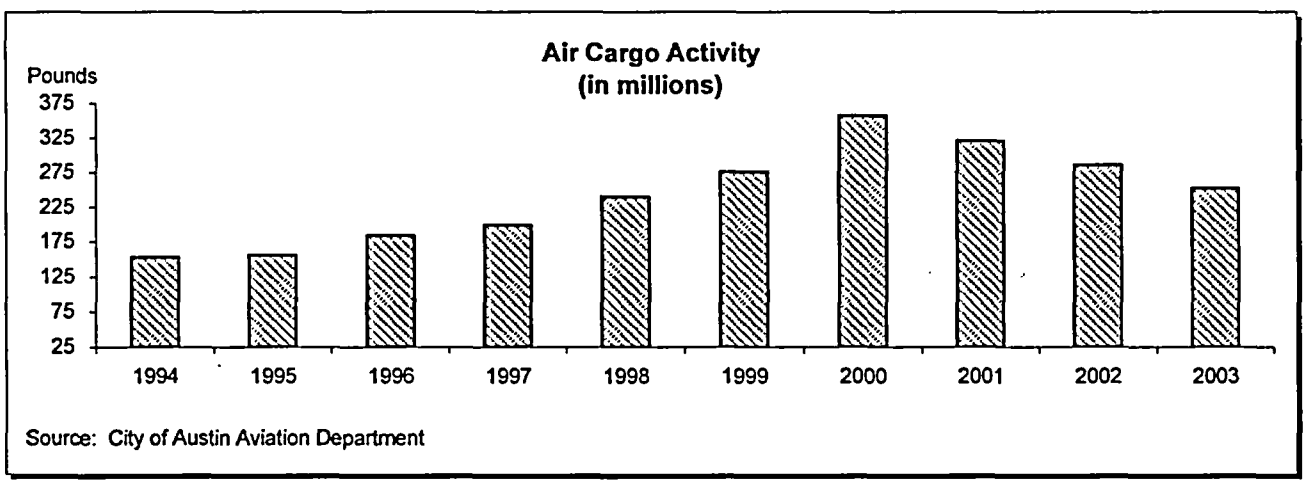
AUSTIN-BERGSTROM INTERNATIONAL AIRPORT *

	Airline Passengers			Cargo Statistics (in millions of pounds)
Year	Enplanements	Deplanements	Total	
1994	2,550,011	2,550,132	5,100,143	153
1995	2,668,447	2,676,240	5,344,687	156
1996	2,853,225	2,838,008	5,691,233	184
1997	2,957,553	2,946,752	5,904,305	199
1998	3,037,566	3,028,407	6,065,973	240
1999	3,363,069	3,307,782	6,670,851	276
2000	3,938,644	3,720,027	7,658,671	357
2001	3,690,835	3,508,487	7,199,322	321
2002	3,439,302	3,281,366	6,720,668	286
2003	3,436,944	3,270,137	6,707,081	252

*Airline passenger and cargo statistics are reported on a calendar year basis; 2003 figures represent activity through December 2003.



Source: City of Austin Aviation Department



Source: City of Austin Aviation Department

Department and Policy	Expires	Annual Premium	Insurer	Limits of Coverage	Coverage Overview
City-wide (Excluding Austin Energy (1)) • All-risk property • Boiler and machinery	10/1/03	$2,170,650	FM Global	$500,000,000	Provides replacement cost coverage for loss or damage to City buildings, and contents due to fire, wind storm, hail, or other perils. Subject to a $100,000 per occurrence deductible. Provides coverage for fine arts owned or on loan subject to $1,000 deductible per claim. Covers Cable TV equipment with $1,000 deductible. Covers damages from boiler and fired pressure vehicle accidents with a $10,000 deductible.
City-wide • Commercial crime	10/20/03	$21,483	Fidelity & Deposit	$5,000,000	Covers loss of funds through public employee dishonesty. Subject to $5,000 deductible.
			Fidelity & Deposit	$1,000,000	Covers loss of funds through forgery or alteration of, on, or in any covered instrument. Subject to $5,000 deductible.
City-wide Selected capital improvement projects ROCIP III • Hired and nonowned auto	2/1/04	Premium is included in the general liability premium and coverage is for a 5 year term.	Zurich North America Insurance Company	$1,000,000 per occurrence	Provides bodily injury and property damage coverage to the City and contractors signed up in the Rolling Owner Controller Insurance Program (ROCIP). Coverage is provided for nonowned and hired vehicles and is intended to be excess over primary auto coverage.
City-wide Selected capital improvement projects ROCIP III • Commercial general liability	2/1/04	$2,101,974 Premium is for a 5 year term. Premium may vary based on experience.	Zurich North America Insurance Company	$2,000,000 per occurrence; $4,000,000 general aggregate	Provides bodily injury, property damage, and completed operations coverage to the City and contractors signed up in the ROCIP program. Coverage is provided only at specified capital improvement project sites participating in the program.
City-wide Selected capital improvement projects ROCIP III • Workers' compensation and employers' liability	2/1/04	Premium included in Commercial general liability above and is for a 5 year term. Premium may vary based on experience.	Zurich North America Insurance Company	Workers' compensation: Statutory Employers' Liability: $1,000,000 each accident $1,000,000 policy limit $1,000,000 each employee	Provides workers' compensation and employers' liability coverage to all contractors working on specified capital improvement project sites participating in the ROCIP program.

(Continued)

(1) Austin Energy maintains appropriate levels of insurance coverage on all property and boiler/machinery, as well as excess liability coverage. Coverage is in compliance with applicable regulations and bond covenants.

Department and Policy	Expires	Annual Premium	Insurer	Limits of Coverage	Coverage Overview
City-wide Selected capital improvement projects ROCIP III • Excess liability	2/1/04	$410,934 Premium is for a 5 year term.	Zurich North America Insurance Company	$8,000,000	Provides excess coverage over the primary auto, employers' liability, and general liability coverage. Self-insured retention is $25,000.
Aviation • Airport liability	3/24/04	$154,000	XL Specialty	$100,000,000	Provides liability protection for operations at the airport. $100,000,000 per occurrence. Personal injury limits of $25,000,000.
Finance • Fidelity bond	5/6/04	$667	Fidelity & Deposit Co. of Maryland	$100,000	Covers loss of funds through employee dishonesty for the Director of Finance and City Treasurer. No deductible applicable.
Health and Human Services Department (HHSD) and Primary Care Department • Medical malpractice		**This coverage was non-renewed**			Provides medical malpractice coverage for physicians. Coverage is on a claims made basis and is offered as a benefit for physicians employed by the City for both HHSD and Primary Care.
Police • Airplane liability • Helicopter liability and hull coverage	12/21/03	$93,050	Old Republic	Airplane–$100,000 per person, $1,000,000 per occurrence Helicopter–$10,000,000 per occurrence	Aircraft physical damage; liability to others; medical expense.
Public Works • Commercial general liability	5/12/04	$4,813	Texas Municipal League	$2,000,000 per occurrence; $4,000,000 general aggregate	Provides bodily injury and property damage coverage to the City. Coverage is provided only for 505 Barton Springs Road, One Texas Center. Purchased for compliance with tenant lease agreements.
Austin Energy Services • Excess liability	12/31/03	$356,124	Aegis	$35,000,000 per occurrence	Provides bodily injury and property damage coverage for the Austin Energy Services of the City. Excess coverage is provided for general liability, automobile liability, and employers' liability.

Hotel-Motel Occupancy Tax
Tax Levied Effective January 1, 1971 (Base Year Is 1972)
1971-2003

City of Austin, Texas
Table 21

Fiscal Year Ended Sept. 30	(In thousands) 1st Quarter Oct. - Dec.	2nd Quarter Jan. - Mar.	3rd Quarter Apr. - Jun.	4th Quarter Jul. - Sept.	Total	Percent Base Year	Annual Increase (Decrease)
	$	$	$	$	$	%	%
1971 (1)	--	--	69	73	142	N/A	N/A
1972	77	67	73	79	296	100.0	0.0
1973	81	72	87	93	333	112.4	12.4
1974	93	81	87	99	360	121.7	8.2
1975	99	94	97	113	403	136.2	12.0
1976	117	103	123	149	492	166.3	22.0
1977 (2)	152	136	186	139	613	207.1	24.5
1978	185	214	237	293	929	313.9	51.6
1979	289	273	308	353	1,223	413.4	31.7
1980	342	321	361	401	1,425	481.3	16.4
1981	410	363	443	481	1,697	573.2	19.1
1982	549	436	507	603	2,095	707.7	23.5
1983	630	520	649	699	2,498	843.9	19.3
1984 (3)	689	642	768	917	3,016	1,019.0	20.7
1985	942	1,492	1,557	1,924	5,915	1,998.3	96.1
1986	1,706	1,438	1,597	1,554	6,295	2,126.7	6.4
1987	1,675	1,224	1,682	1,569	6,150	2,077.8	(2.3)
1988	1,379	1,329	1,523	1,709	5,940	2,006.9	(3.4)
1989	1,675	1,684	1,907	2,127	7,393	2,497.7	24.5
1990	1,879	1,620	1,919	2,152	7,570	2,557.5	2.4
1991	1,942	1,860	2,154	2,351	8,307	2,806.6	9.7
1992	2,224	1,957	2,317	2,622	9,120	3,081.2	9.8
1993	2,463	2,260	2,779	3,011	10,513	3,552.0	15.3
1994	2,727	2,409	2,897	3,444	11,477	3,877.5	9.2
1995	3,115	2,870	3,501	3,654	13,140	4,439.5	14.5
1996	3,494	3,203	3,763	3,800	14,260	4,817.8	8.5
1997	3,537	3,353	3,860	4,468	15,218	5,141.5	6.7
1998 (4)	4,539	4,284	4,936	5,061	18,820	6,358.4	23.7
1999	5,612	5,552	6,375	7,073	24,612	8,315.4	30.8
2000	6,637	6,264	7,573	8,284	28,758	9,716.1	16.8
2001 (5)	7,595	7,671	8,043	7,836	31,145	10,522.4	8.3
2002	5,832	5,355	6,350	7,222	24,759	8,365.2	(20.5)
2003	5,766	5,874	7,045	6,823	25,508	8,618.1	3.0

(1) 3% tax levied effective January 1, 1971. Section 32-32(a) of Article V of Chapter 32 of the 1967 Code of the City of Austin.
(2) Tax levy increased to 4% effective October 1, 1977. Ordinance No. 770901-1 amended Section 32-32(a) of Article V of Chapter 32 of the 1967 Code of the City of Austin.
(3) Tax levy increased to 7% effective October 1, 1984. Ordinance No. 840712-U amended Section 5-3-2(a) of Chapter 5-3 of Title V of the 1981 Code of the City of Austin.
(4) Tax levy increased to 9% effective August 1, 1998. Ordinance No. 980709-G amended Section 5-3-2(a) of Chapter 5-3 of Title Vof the 1981 Code of the City of Austin.
(5) Beginning in fiscal year 2001, the City implemented GASB Statement No. 33, which changes the method of reporting tax collections in the City's financial statements. This table will continue to be reported on a cash basis to provide a more meaningful comparison.

Vehicle Rental Tax
Tax Levied Effective January 1, 1999 (Base Year Is 2000)
1999-2003

City of Austin, Texas
Table 22

Fiscal Year Ended Sept. 30	(In thousands) 1st Quarter Oct. - Dec.	2nd Quarter Jan. - Mar.	3rd Quarter Apr. - Jun.	4th Quarter Jul. - Sept.	Total	Percent Base Year	Annual Increase (Decrease)
	$	$	$	$	$	%	%
1999 (1)	–	–	983	1,177	2,160	N/A	N/A
2000	1,185	1,136	1,421	1,509	5,251	100.0	0.0
2001 (2)	1,468	1,460	1,379	1,420	5,727	109.1	9.1
2002	1,258	1,085	1,154	1,259	4,756	90.6	(17.0)
2003	1,130	1,127	1,044	1,162	4,463	85.0	(6.2)

(1) 5% tax levied effective January 1, 1999. Ordinance No. 981210-A.

(2) Beginning in fiscal year 2001, the City implemented GASB Statement No. 33, which changes the method of reporting tax collections in the City's financial statements. This table will continue to be reported on a cash basis to provide a more meaningful comparison.

Date of Incorporation:	December 27, 1839		
Date first Charter adopted:	December 27, 1839		
Date present Charter adopted:	January 31, 1953		
Form of Government:	Council - Manager		
Number of Employees:	10,463		
Elections:			
Number of registered voters,			
May 3, 2003 (Mayor and 3 Council members)	401,271	City of Austin	
June 7, 2003 (Runoff - Place 5)	401,873	City of Austin	
Number of votes cast in:			
Last general municipal election,			
May 3, 2003	59,929		
Last general municipal election runoff			
June 7, 2003	38,895		
Percentage of registered voters voting in:			
Last general municipal election, May 3, 2002	15%		
Last general municipal election runoff	10%		
June 7, 2003			
Fire protection:			
Number of stations	41		
Number of employees	1,063		
Number of alarms answered	58,988		
Number of employees per			
1,000 population (1) (3)	1.5759		

Police protection:	
Number of employees	1,698
Number of law offenses	130,478
Number of arrests (4)	116,769
Vehicle patrol units	318
Number of employees per 1,000 population (1) (3)	2.519
Library:	
Central and branch libraries	22
Volumes in collection	1,550,145
Materials circulated	3,332,645
Registered borrowers	484,075
Recreation:	
District parks	11
Metropolitan parks	11
Natural preserves	15
Neighborhood parks	85
Special parks (museums and miscellaneous)	26
Greenbelts	25
Golf courses	6
Swimming pools	47
Recreation centers	17
Youth entertainment complex	1
Senior activity sites	20
Athletic fields	87
Tennis courts	102
Open fields	89
Senior activity centers	3
Veloway	3.1 miles
Hike and bike trails	75 miles

POPULATION ANALYSIS

	Austin (1)		Travis County (1)		Texas (2)		United States (2)	
Year	Population	Percentage Change	Population	Percentage Change	Population	Percentage Change	Population	Percentage Change
		%		%		%		%
1940	87,930	--	111,053	--	6,414,824	--	132,165,000	--
1950	132,459	50.64	160,980	44.96	7,711,194	20.21	151,326,000	14.50
1960	186,545	40.83	212,136	31.78	9,579,677	24.23	179,323,000	18.50
1970	253,539	35.91	295,516	39.30	11,198,655	16.90	203,302,000	13.37
1980	345,496	36.27	419,573	41.98	14,228,383	27.05	222,110,000	9.25
1985	406,584	17.68	527,120	25.63	16,370,000	15.05	238,740,000	7.49
1990	450,830	10.88	576,407	9.35	16,986,510	3.77	249,632,692	4.56
1995	523,352	16.09	656,979	13.98	18,724,000	10.23	262,755,000	5.26
1996	541,889	3.54	681,654	3.76	19,128,000	2.16	265,410,000	1.01
1997	560,939	3.52	703,717	3.24	19,439,337	1.63	267,792,000	0.90
1998	608,214	8.43	725,669	3.12	19,759,614	1.65	271,685,044	1.45
1999	619,038	1.78	744,857	2.64	20,044,141	1.44	272,690,813	0.37
2000	628,667	1.56	749,426	0.61	20,044,141	0.00	272,690,813	0.00
2001	661,639	5.24	837,206	11.71	20,851,820	4.03	281,421,906	3.20
2002	671,044	1.42	848,484	1.35	21,779,893	4.45	288,368,698	2.47
2003	674,719	0.55	865,497	2.01	22,118,509	1.55	290,809,777	0.85

(1) All years are estimates from the City's Department of Development and Review based on full purpose area as of December 31. Census years are modified to conform to U.S. Bureau of the Census data. Estimates for 1985 were revised in 1990 based on the 1990 census. Number of employees per 1,000 population is based on projected population of 674,382.

(2) U.S. Bureau of the Census official estimates as of July 31, except for census years; 2000 data available April 2001.

(3) Represents civilian and sworn employees.

(4) Due to the conversion to a new records management system, total arrests for 2003 are not comparable to prior years. Total arrests reported in prior years are based on the highest offense in a police report. Total arrests in 2003 represent the total number of arrests for all offenses on a police report.

Year	Area of Incorporation (Sq. Miles)	Population (1)	Utility Connection (2)			Effective Buying Income (EBI) (4)	
			Electric (3)	Water	Gas	Median Household EBI	Per Capita EBI
						$	$
1994	192.16	507,468	298,662	148,148	142,373	32,062	17,487
1995	196.68	523,352	306,670	149,867	147,023	33,981	18,490
1996	195.74	541,889	319,518	151,757	148,124	29,803	16,685
1997	232.26	560,939	326,816	156,397	156,752	31,362	17,494
1998	253.67	608,214	342,263	168,907	165,274	33,690	18,999
1999	252.30	619,038	348,721	173,038	173,150	36,532	18,973
2000	264.90	628,667	344,134	176,096	172,063	36,321	20,790
2001	265.80	661,639	349,671	178,608	172,177	39,811	22,241
2002	273.10	671,044	359,358	182,977	193,278	47,089	25,109
2003	275.58	674,719	363,377	184,659	199,042	41,909	22,420
1994-2003 Change	43.41%	32.96%	21.67%	24.64%	39.80%	30.71%	28.21%

Year	Building Permits			Retail Sales (Austin) (5)	Austin Area Home Sales (6)	
	Federal, State and Municipal	Taxable	Total		Average Sale Price	Number of Homes Sold
	$	$	$	$	$	
1994	19,643,501	840,043,119	859,686,620	6,784,452,526	120,161	10,833
1995	11,087,831	870,446,315	881,534,146	7,286,274,112	126,726	8,436
1996	89,945,847	1,246,232,619	1,336,178,466	7,932,937,305	132,699	9,773
1997	2,574,539	1,023,114,762	1,025,689,301	8,513,655,224	146,763	8,094
1998	46,722,845	1,434,660,615	1,481,383,460	10,842,488,373	155,600	10,536
1999	54,399,189	1,501,435,229	1,555,834,418	11,279,844,061	166,272	12,284
2000	34,334,286	1,797,039,075	1,831,373,361	13,577,833,634	196,308	12,972
2001	71,189,116	1,625,508,854	1,696,697,970	12,542,967,960	154,000	12,444
2002	38,727,017	1,261,868,130	1,300,595,147	12,422,963,735	159,000	12,837
2003	17,084,652	1,189,489,091	1,206,573,743	12,097,570,479	201,505	16,563
1994-2003 Change	(13.03)%	41.60%	40.35%	78.31%	67.70%	52.89%

Note: All numbers are as of fiscal year ended September 30, except where noted.

(1) Figures represent full purpose population as of December 31 for each year.
(2) Figures are as of September 30.
(3) Figures exclude nightwatchman billings.
(4) Source: 2003 Survey of Buying Power, Sales and Marketing Management.
(5) Source: State of Texas Comptroller's Office. Amount is an estimate based on State of Texas Comptroller's Office data.
(6) Source: Austin Board of Realtors.

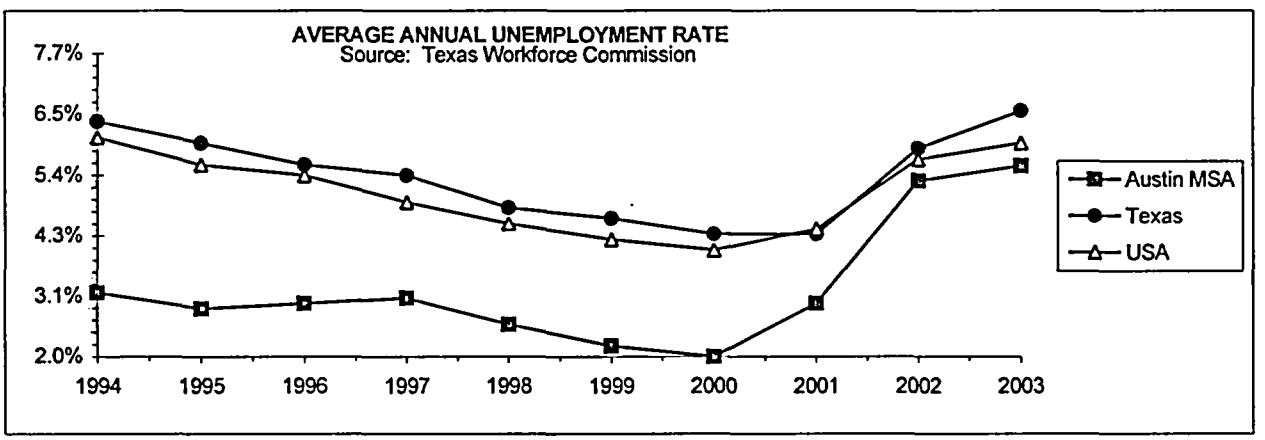
EMPLOYMENT BY INDUSTRY IN THE AUSTIN METROPOLITAN STATISTICAL AREA (1)

	2003		2000		1990		1980	
Industrial Classification	Number	% of Total	Number	% of Total	Number	% of Total	Number	% of Total
Manufacturing	60,483	9.1	84,662	12.9	49,300	12.9	31,014	12.8
Government	148,433	22.4	137,171	20.9	110,400	28.8	78,263	32.3
Trade, transportation, & utilities (2)	113,183	17.0	171,771	26.2	90,500	23.6	59,121	24.4
Services and miscellaneous	265,342	40.0	190,048	28.9	97,200	25.3	44,826	18.5
Finance, insurance and real estate	37,850	5.7	32,031	4.9	23,400	6.1	14,296	5.9
Contract construction	37,008	5.6	39,134	6.0	12,000	3.1	14,053	5.8
Natural resources and mining	1,776	0.3	1,353	0.2	700	0.2	727	0.3
Totals	664,075	100.1	656,170	100.0	383,500	100.0	242,300	100.0

Source: Texas Workforce Commission (TWC).

(1) Austin-San Marcos MSA includes Travis, Bastrop, Caldwell, Hays, and Williamson Counties. Numbers for 2003 are an estimate based on TWC and the Bureau of Labor Statistics, and U.S. Department of Labor data as of March 31st.

(2) Trade, transportation and utilities are reported together as of 2003.



TEN LARGEST EMPLOYERS
September 30, 2003

Employer	Product or Service	Number of Employees	% of Total (3)
			%
The University of Texas at Austin	Education and research	20,249	3.0
Dell Computer Corporation	Computers	16,000	2.4
City of Austin	City government	10,463	1.6
Austin Independent School District	Education	10,408	1.6
Motorola, Inc.	Electronic components	8,500	1.3
IBM Corporation	Office machines	6,500	1.0
Seton Healthcare Network	Hospital	6,393	1.0
Internal Revenue Service	Federal agency	5,000	0.8
HEB Grocery	Grocery/pharmacy	6,200	0.9
St. David's Healthcare Partnership	Healthcare	4,833	0.7
		94,546	14.3

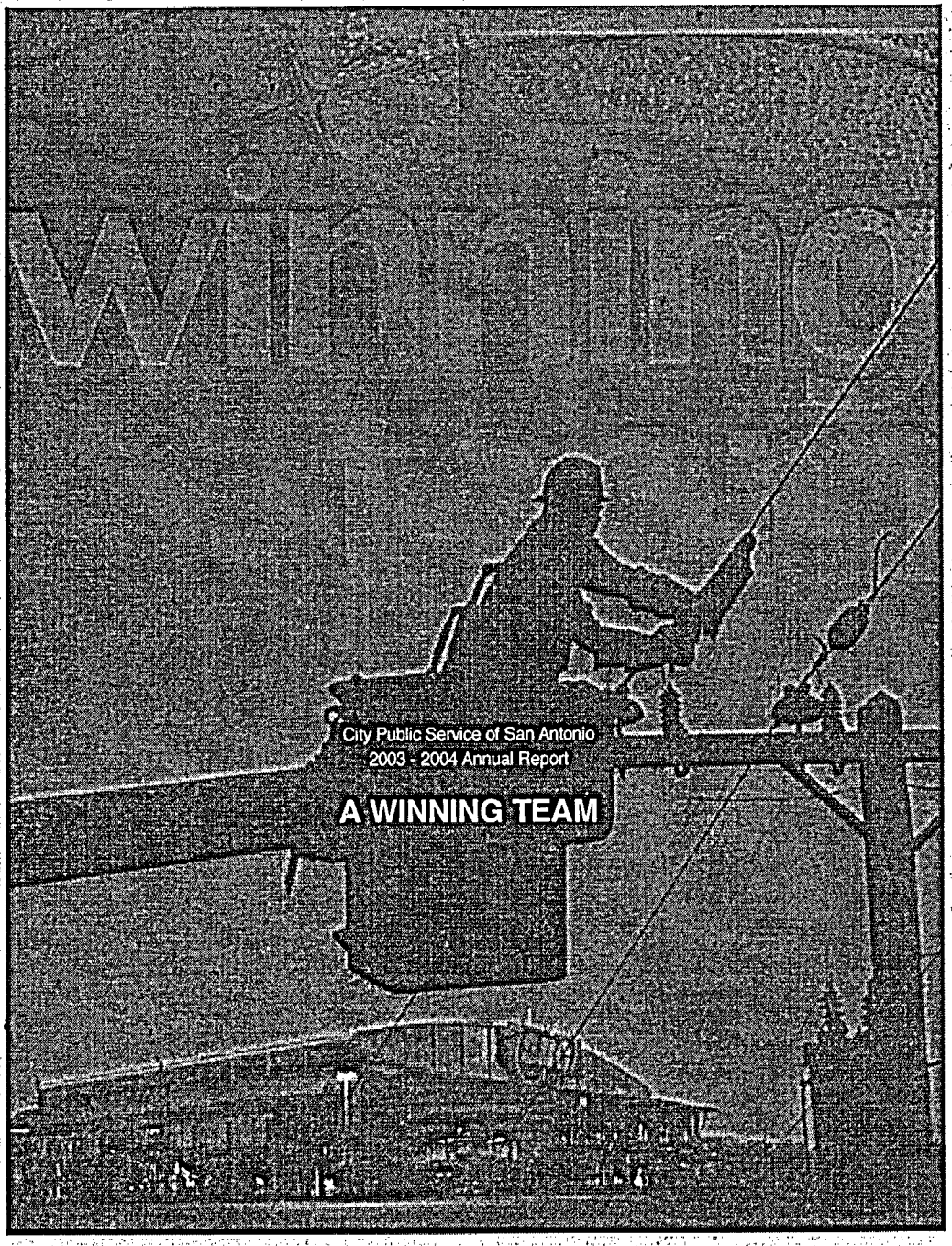
Source: Austin Chamber of Commerce and Austin Business Journal

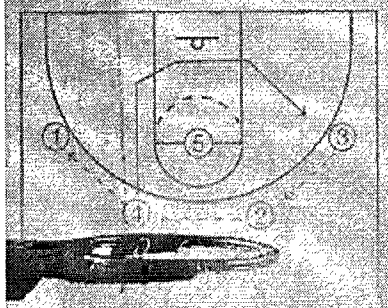
(3) Total refers to total work force of 664,075 as stated in the "Employment by Industry" table above.

Elements of Budget Fund Balance
for Selected Operating Funds (in thousands)
September 30, 2003

City of Austin, Texas
Table 26

	Reserve for Encumbrances	Inception-to-Date Change in Fair Value
General Fund	$ 4,123	128
Special Revenue Funds:		
Fiscal Surety - Land Development	--	383
Enterprise Funds:		
Electric	7,901	1,025
Water and Wastewater:		
Water	842	295
Wastewater	723	295
Airport	738	404
Convention Center	179	824
Drainage	376	--
Golf	20	--
Hospital	130	--
Parks and Recreation:		
Softball	2	--
Recreation Centers	15	--
Primary Care	493	--
Solid Waste Services	167	--
Transportation	1,653	--
Internal Service Funds:		
Capital Projects Management	86	--
Employee Benefits	49	--
Fleet:		
Operating	416	223
Designated for acquisition	35	--
Information Systems	1,430	--
Liability Reserve	566	--
Support Services	2,297	--
Wireless Communication	33	--
Workers' Compensation	14	--


City Public Service of San Antonio
2003 - 2004 Annual Report
A WINNING TEAM



On the cover, a CPS lineman – against the backdrop of the new SBC Center, home of the NBA Spurs championship basketball team - helps provide reliable electric service to more than 600,000 customers in Greater San Antonio.

STAT SHEET

City Public Service (CPS) is the nation s largest municipally owned energy company providing both natural gas and electric service.

Electric customers: 602,313
Natural gas customers: 306,845
Service territory: 1,566 square miles in Bexar County, Texas, including metropolitan San Antonio and portions of seven neighboring counties

Electric generation capacity: 5,116 megawatts (MW)
Generation sources: coal, 49%, nuclear, 24%, natural gas/oil, 17%, wind energy and other purchased power, 10%.

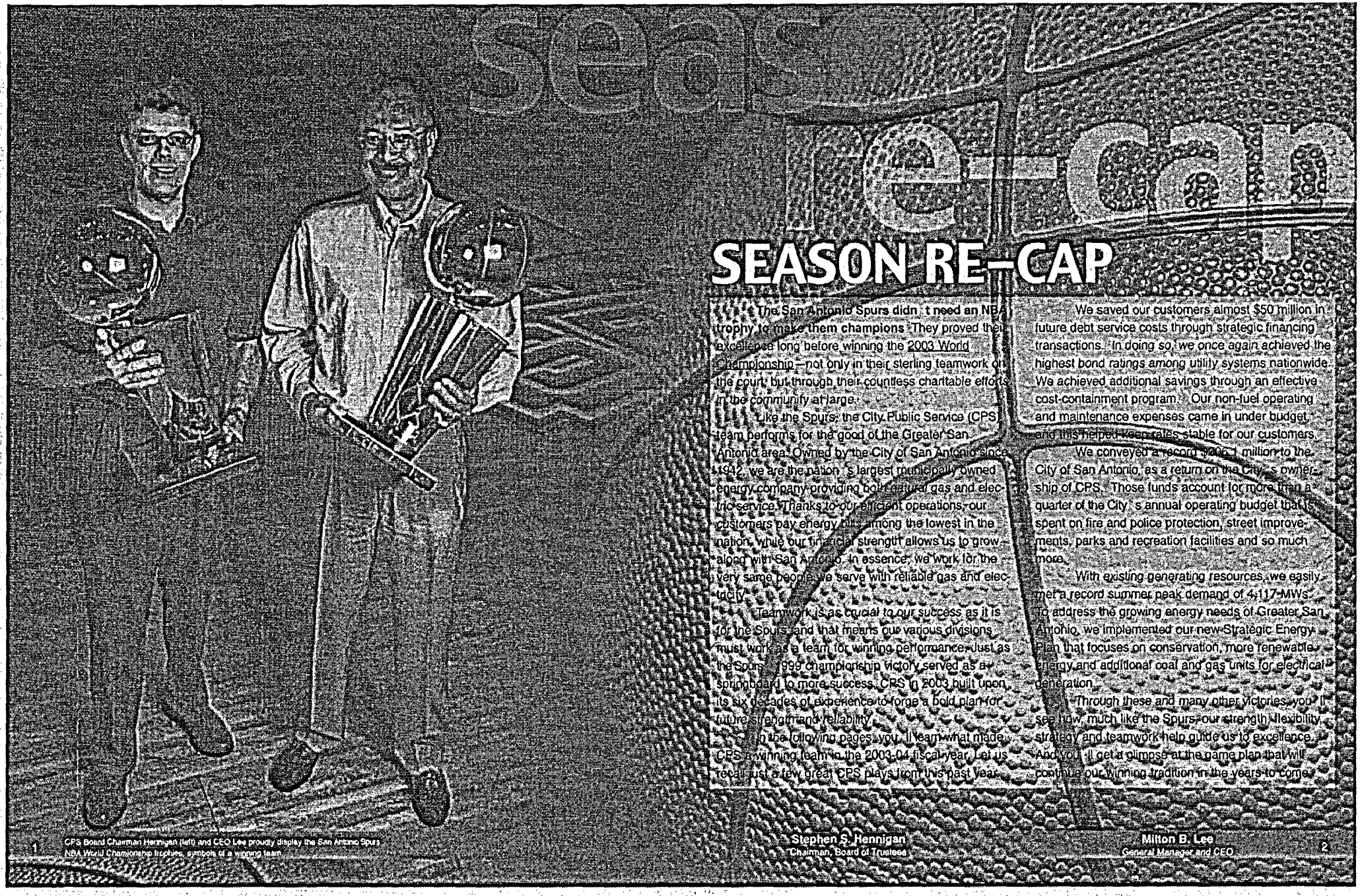
Owned by: City of San Antonio, Texas, the nation s ninth largest city. Fourteen percent of CPS gross revenue is returned to the City of San Antonio, an amount that makes up more than one-quarter of the City s annual budget.

Proceeds to City of San Antonio for FY2003-04: $206.1 million, a new record.

Governed by: independent, five-member Board of Trustees, including the Mayor of the City of San Antonio.

Table of Contents

page 1 - season recap; **page 3** - strength; **page 7** - flexibility; **page 11** strategy; **page 15** - teamwork; **page 19** - financial and operating review; **page 21** - five year highlights-unaudited; **page 22** - five year operations review-unaudited; **page 23** - report of management; **page 24** - financial statement; **page 61** - team leaders



SEASON RE-CAP

The San Antonio Spurs didn't need an NBA trophy to make them champions. They proved their excellence long before winning the 2003 World Championship – not only in their sterling teamwork on the court, but through their countless charitable efforts in the community at large.

Like the Spurs, the City Public Service (CPS) team performs for the good of the Greater San Antonio area. Owned by the City of San Antonio since 1942, we are the nation's largest municipally owned energy company providing both natural gas and electric service. Thanks to our efficient operations, our customers pay energy bills among the lowest in the nation, while our financial strength allows us to grow aligned with San Antonio. In essence, we work for the very same people we serve with reliable gas and electricity.

Teamwork is as crucial to our success as it is for the Spurs, and that means our various divisions must work as a team for winning performance. Just as the Spurs' 1999 championship victory served as a springboard to more success, CPS in 2003 built upon its six decades of experience to forge a bold plan for future strength and reliability.

In the following pages, you'll learn what made CPS a winning team in the 2003-04 fiscal year. Let us recall just a few great CPS plays from this past year.

We saved our customers almost $50 million in future debt service costs through strategic financing transactions. In doing so, we once again achieved the highest bond ratings among utility systems nationwide. We achieved additional savings through an effective cost-containment program. Our non-fuel operating and maintenance expenses came in under budget, and this helped keep rates stable for our customers.

We conveyed a record $240.1 million to the City of San Antonio, as a return on the City's ownership of CPS. Those funds account for more than a quarter of the City's annual operating budget that is spent on fire and police protection, street improvements, parks and recreation facilities and so much more.

With existing generating resources, we easily met a record summer peak demand of 4,117 MWs. To address the growing energy needs of Greater San Antonio, we implemented our new Strategic Energy Plan that focuses on conservation, more renewable energy and additional coal and gas units for electrical generation.

Through these and many other victories, you'll see how, much like the Spurs, our strength, flexibility, strategy and teamwork help guide us to excellence. And you'll get a glimpse at the game plan that will continue our winning tradition in the years to come.

CPS Board Chairman Hennigan (left) and CEO Lee proudly display the San Antonio Spurs NBA World Championship trophies, symbols of a winning team.

Stephen S. Hennigan
Chairman, Board of Trustees

Milton B. Lee
General Manager and CEO

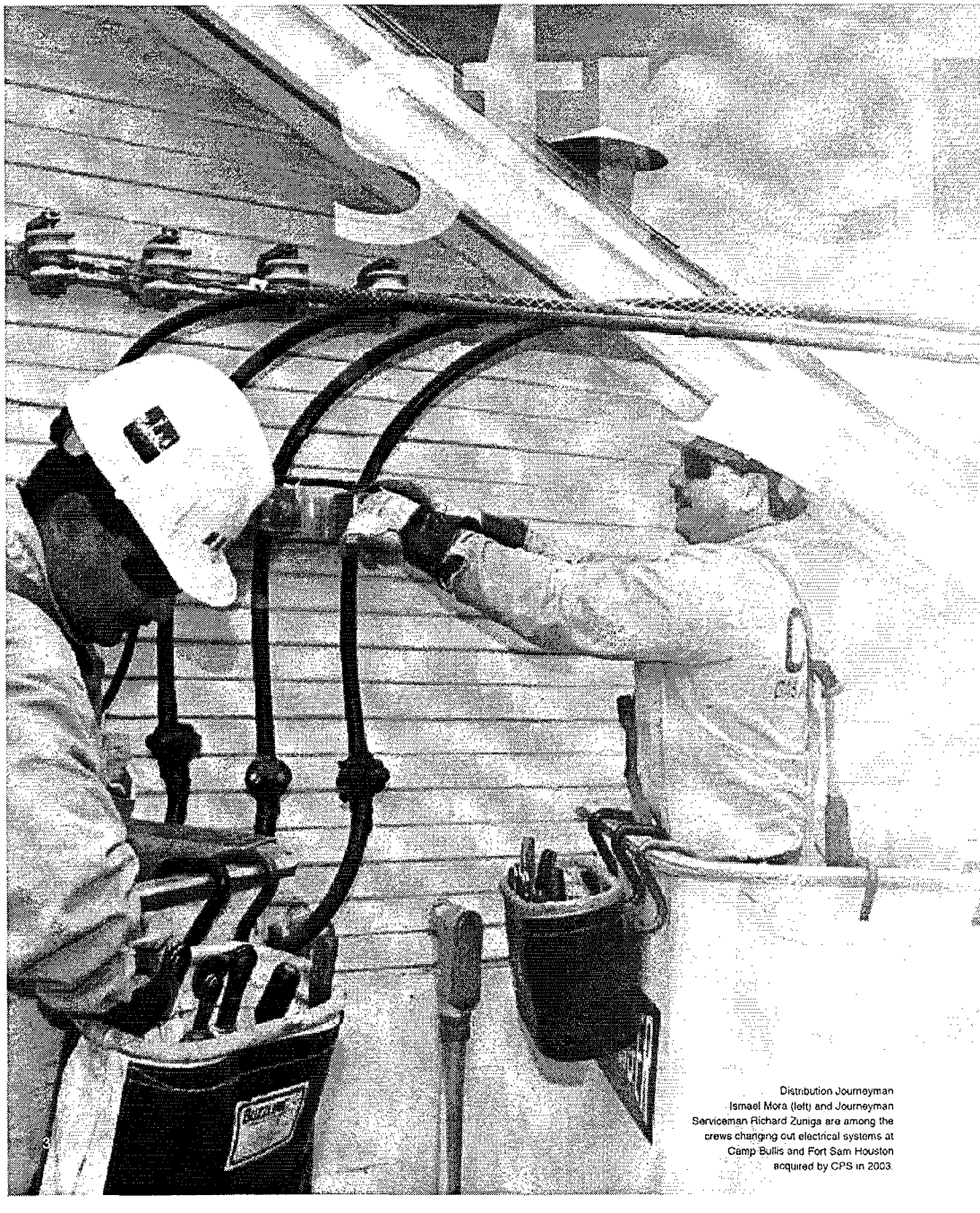
STRENGTH

Whether they re skilled in fast breaks, daring steals or three-point sharpshooting, great teams rely on a strong roster of powerful players to help them win even the toughest matchups. They hone this strength through dedicated practice, and enhance it with wise, careful acquisitions of new talent. Like the Spurs, CPS achieves excellence with a rock-solid foundation of well-run facilities and well-managed finances, and consistently seeks to expand that strength through new facilities that enhance our reliability and investment activities that are secure, yet give us the highest returns.

Greater San Antonio continued to grow in 2003, and CPS worked to meet the challenge with new infrastructure. Most notably, CPS assumed control of all electrical facilities at the U.S. Army s Fort Sam Houston and at Camp Bullis, an Army training installation northwest of San Antonio. We also began planning a new high-voltage transmission line to serve the growing area to the west and northwest of San Antonio, working extensively with customers along proposed routes to determine the best possible route. To monitor the flow of energy throughout CPS ever-growing network of gas and electric lines, CPS broke ground on a new, state-of-the-art Energy Management Center in eastern San Antonio. And CPS prepared to accommodate the energy needs of a major new corporate citizen, Toyota, which is building a new pickup truck assembly plant that will employ 2,000 when it opens in 2006.

CPS matched its physical strength with fiscal strength, maintaining its reputation for prudent financial planning that has earned it a AA+ rating from Fitch Ratings, a Aa1

Strength continued on next page



Distribution Journeyman Ismael Mora (left) and Journeyman Serviceman Richard Zuniga are among the crews changing out electrical systems at Camp Bullis and Fort Sam Houston acquired by CPS in 2003.

Flags of many nations are reflected in photovoltaic panels at the CPS-ITC Solar Power Station on the grounds of the University of Texas at San Antonio s Institute of Texan Cultures. The power station, which generates and feeds 10 kilowatts of power into the downtown San Antonio grid, also includes an informational kiosk to educate visitors about renewable energy.

STRENGTH cont.

rating from Moody s Investors Service Inc., and a AA+ rating from Standard & Poor s Ratings Services for its senior lien debt.

In the 2003-04 fiscal year, we saved our ratepayers $1.4 million in interest costs by restructuring our New Series 2002 Bond Escrow to take advantage of changing interest rates on escrow investments. In May, CPS provided funds for capital projects with the sale of $250 million in variable rate demand obligations. We also completed two separate bond refunding transactions totaling $444.4 million. CPS will realize almost $50 million in savings from these refundings.

We continued to expand our alternative energy portfolio. Our Windtricity™ program breezed along, supplying 160 MW of clean, renewable electricity from the Desert Sky Wind Farm in West Texas. CPS also teamed up with the Institute of Texan Cultures (ITC), a cultural center focusing on the contributions of numerous ethnic groups to the Lone Star State, to unveil the CPS-ITC Solar Power Station on the Institute s grounds near Hemisfair Park. The demonstration station s 200 photovoltaic cells generate 10 kilowatts of power, enough to run three average homes under peak conditions.

CPS also joined forces with Southwest Research Institute, the U.S. Department of Defense and others to kick off two experimental fuel cell projects at Brooks City-Base, a research park that once was Brooks Air Force Base. One emission-free hydrogen fuel cell was installed at the Challenger Learning Center, an aerospace education facility, while three others were located in Brooks City-Base s housing area – South Texas first application of fuel cells for residential use.

In 2003, CPS broke ground on its state-of-the-art Energy Management Center in eastern San Antonio. When it s opened in late 2004, the EMC will become the heart of CPS energy distribution.

FLEXIBILITY

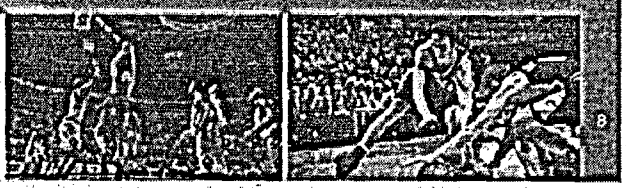
On the court, games can be won or lost in the blink of an eye. To succeed, the Spurs must master flexibility, responding quickly to changing game conditions. Thanks to a wide variety of players with unique sets of skills, CPS, like the Spurs, can tackle any challenge with speed and agility. CPS knows the importance of flexibility and works quickly to respond to challenges and to find innovative solutions.

In February 2003, extreme winter weather in the Northeast sent demand for natural gas skyward, causing prices to reach record highs nationwide. In response, CPS purchased gas at the most favorable prices available from multiple suppliers. Before July 2002, CPS had only one source for gas, but the construction of new pipelines and other facilities now enables CPS to buy gas from more than 30 suppliers. CPS also used stored gas purchased at lower prices to help lessen the financial impact on customers. Meanwhile, our conservation experts continued to educate customers on ways to save energy and lower their bills.

In August, 102-degree weather pushed electrical peak demand to a new record of 4,117 MW, but well within CPS' generating capacity of 5,116 MW. CPS also was able to fully meet customer electrical demand despite a six-month outage of Unit 1 at the South Texas Project (STP) nuclear power plant near Bay City. With the guidance and oversight of the Nuclear Regulatory Commission, the STP staff worked expeditiously to repair several welds on the bottom of the reactor that allowed the seepage of a tiny amount of reactor coolant fluid.

Flexibility continued on next page

CPS used stored gas, purchased at lower prices, to help lessen the financial impact of gas prices on customers' bills.

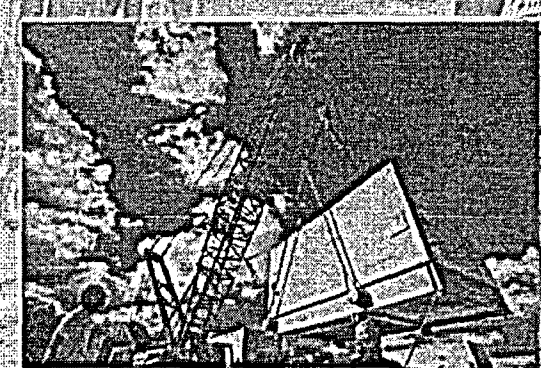


FLEXIBILITY cont.

CPS also demonstrated flexibility in its choice of fuels, from its power plants to its cars and trucks. Our diversified nuclear, natural gas, oil, coal-fired and wind-powered generation helped reduce the effects of higher gas costs on our customers' electric bills. CPS also expanded the portion of its motor pool using lower-emission fuels like ethanol and biodiesel. With 37 percent of its cars and trucks running cleaner and greener, CPS leads Texas in its use of alternatively fueled vehicles.

Within the company, CPS launched powerful new technology to bring useful information to employees' fingertips. CPSnet, the redesigned corporate intranet, makes it easier than ever for employees to get the information they need to do their jobs well. Designed and built in-house at a fraction of the typical cost, CPSnet was honored with a 2003 "Best of Texas" award by the Texas Public Relations Association.

In 2003, CPS expanded its use of lower-emission fleet vehicles. With 37 percent of its vehicles using cleaner, greener fuels, CPS leads Texas in its use of alternatively fueled vehicles.



Cranes position one of four natural gas peaking units installed by CPS at one of its older plants in an effort to support the ever-growing demand of its service territory. These units will be operational in summer 2004.

STRATEGY

Every winning team needs a solid game plan. The Spurs' coaching staff must craft strategies to match the current conditions on the court without forgetting about the quarters still to be played. Similarly, CPS always keeps an eye on the future, laying the groundwork now for continuing success for years to come.

In 2003, CPS announced its Strategic Energy Plan, a decade-long road map designed to meet the energy needs of the ever-growing Greater San Antonio area. Highlights of the plan include acquiring approximately 150 MW of additional wind-generated electricity; continuing to explore solar, fuel cell and other renewable-energy technologies; installing new gas-fired generating peaking units; and constructing a state-of-the-art, coal-fired plant with the latest environmental safeguards of approximately 750 MW.

As part of the public input process on the Strategic Energy Plan, local elected officials, business leaders and the community at large recognized CPS for its continued leadership on environmental stewardship. CPS' coal-fired facilities currently rank as some of the lowest-emitting facilities in the nation. Yet, in response to public input, CPS' Board of Trustees announced an aggressive plan to further reduce emissions from existing plants. This commitment includes environmental retrofits such as baghouses and scrubbers.

Strategy continued on next page

CPS will retrofit Deely Power Plant with scrubbers, similar to the Spruce Power Plant building shown here, and a baghouse in order to ensure that no net increase in emissions results from the addition of a new coal plant.

STRATEGY cont.

Furthermore, the Board committed to adding renewable energy capacity equal to 10 percent of San Antonio's peak electrical demand by the year 2015, compared to today's capacity which equals about 4 percent of peak electrical demand. The Board also committed CPS to working with a committee of interested citizens and energy-efficiency experts to develop a more aggressive conservation program that is appropriate for the community s needs.

Northwest of San Antonio, CPS worked with the Lower Colorado River Authority to select a route for a new transmission line that will supply additional power to one of the fastest-growing areas in the state and further improve reliability of the Texas electric grid. The Cagnon-to-Kendall 345-kilovolt transmission line project remains under development, as CPS works with the community to determine the least-intrusive, most-appropriate route for the new line.

CPS also involved employees in charting the company s future with formation of the Jupiter Team. Volunteers from throughout the company, working with CPS top executives and Board of Trustees, are currently consulting with employees to determine the necessary steps to successfully propel CPS into the next decade and beyond. As part of the Jupiter Team s "Vision 2020" plan, employees are participating in defining the utility s core values and purpose and identifying a big, audacious goal for the company.

CPS diversified electrical generation fuels mix – including wind energy – is providing energy to many new retail outlets throughout growing Greater San Antonio.

Among the initiatives outlined in CPS' Strategic Energy Plan is the commitment to have renewable capacity equal to 10 percent of peak demand by 2015. That means adding to the 16.5 megawatts of wind power currently purchased by CPS and sold to customers as Windtricity™.

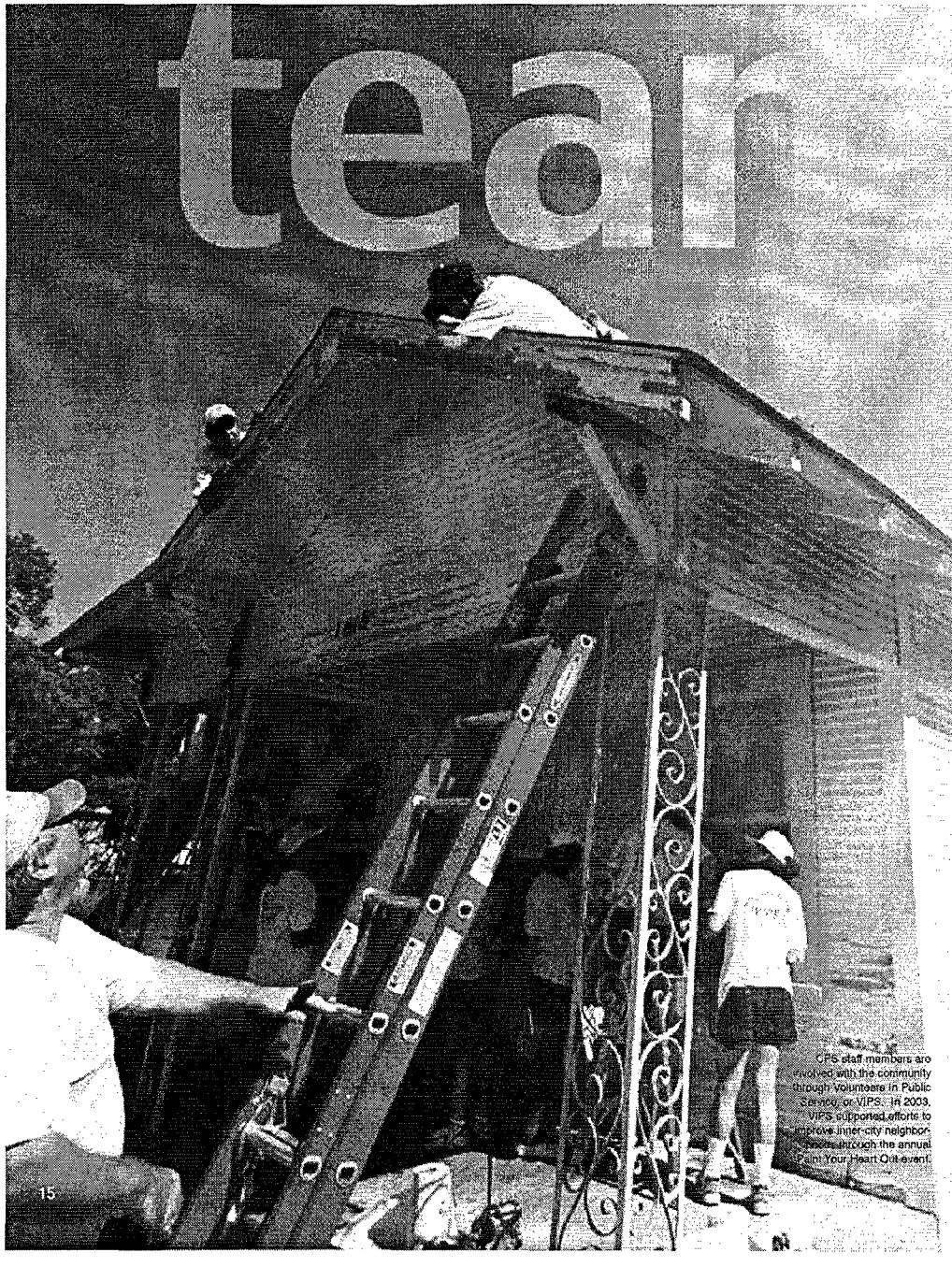
TEAMWORK

While other franchises may rely on one or two flashy superstars, the Spurs consistently triumph by drawing upon the talents and coordination of their entire team. And just as the Spurs organization works together to create a winner, CPS teams up with the citizens of Greater San Antonio in an effort to improve community life.

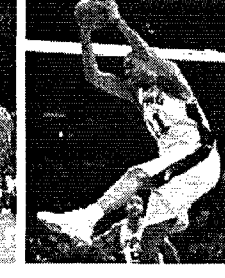
CPS employee volunteers made a difference throughout San Antonio in the 2003-04 fiscal year. In addition to summer fan, holiday toy and winter coat drives for the underprivileged, CPS employees weatherized 500 older, inner-city homes – many of them occupied by the elderly and families with small children – during its spring and summer Cool Volunteers program. Our employees further demonstrated their dedication to their community as a United Way campaign Pacesetter organization, pledging more than $700,000 in the fall 2003 company-wide campaign.

CPS also encouraged customers to adopt environmentally friendly technology with

Teamwork continued on next page



CPS staff members are involved with the community through Volunteers in Public Service, or VIPS. In 2003, VIPS supported efforts to improve inner-city neighborhoods through the annual Paint Your Heart Out event.



TEAMWORK

the 2003 Energy Innovator Awards, honoring San Antonio-area homeowners and businesses that used the latest energy-conserving techniques and renewable energy technology. Our Smart Energy program, in partnership with more than a dozen local builders, gave local homebuyers an easy way to identify homes with an efficient, money-saving combination of electric and natural gas service.

In addition to our ever-popular safety fairs and school presentations, CPS introduced Greater San Antonio s children to the PowerPals™, a quintet of energy superheroes who teach powerful lessons about safety and conservation. The PowerPals are featured on the CPS Kids Web site, also launched in 2003, which blends education and information with a healthy dose of fun.

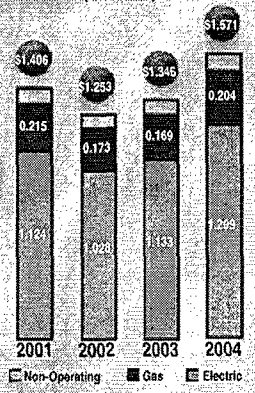
Strength, flexibility, strategy and teamwork – these are the attributes we relied upon for a successful 2003-04 fiscal year. And they re also qualities that will help make CPS a winning team for many seasons to come.

CPS employees supported San Antonio's community-wide fan drive by donating funds to purchase approximately 800 fans. The fans were distributed to people in need – many of whom do not have air conditioning.

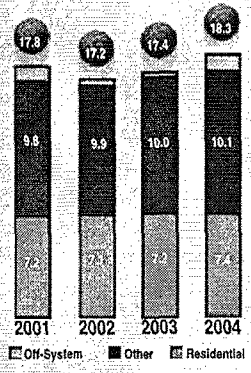
The PowerPals™ Buckley, Sunshine, Gladys, Gearon and Wattson visit with school children throughout the Greater San Antonio area to educate them about energy use and to promote safety not about natural gas and electricity.

financial and operating review

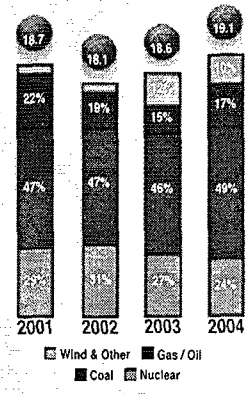
TOTAL REVENUE
Fiscal Year Ending January 31
(in $Billions)



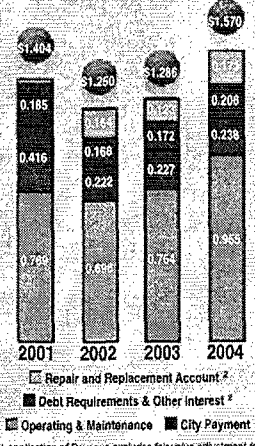
ELECTRIC SALES
Fiscal Year Ending January 31
(In Million MWh)



ELECTRIC GENERATION & OTHER POWER
Fiscal Year Ending January 31
(in Million MWh)

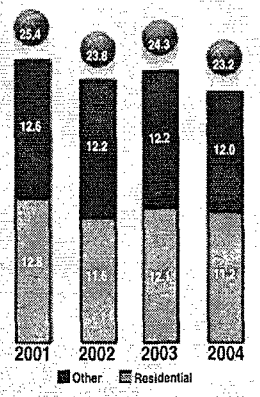


APPLICATION OF REVENUE [1]
Fiscal Year Ending January 31
(in $Billions)

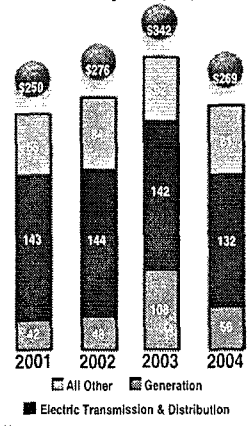


(1) Application of Revenue excludes fair value adjustment for investments; FY 2003 & 2004 excludes unbilled revenues.
(2) FY 2001 includes cash defeasance of debt.

GAS SALES
Fiscal Year Ending January 31
(In Million MCF)



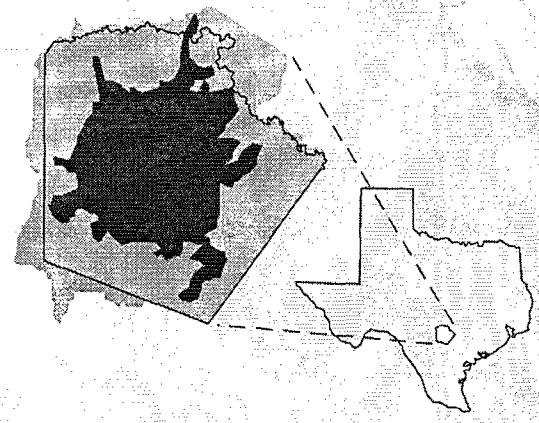
CONSTRUCTION & NET REMOVAL COSTS EXPENDITURES
Fiscal Year Ending January 31 (in $Millions)



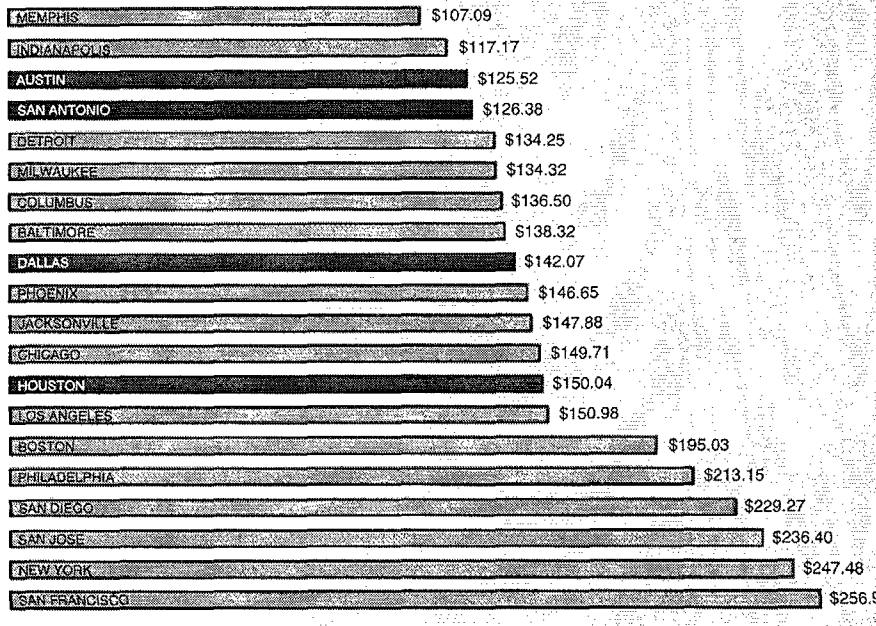
SERVICE AREA

CPS serves 602,313 electric customers primarily within a 1,566-square-mile retail service area including all of Bexar County and small portions of adjacent counties – Atascosa, Bandera, Comal, Guadalupe, Medina, Wilson and Kendall.

CPS' 306,845 gas customers are situated in Bexar and Comal counties.



COMPARISON OF RESIDENTIAL ELECTRIC AND GAS BILLS FOR THE 20 LARGEST U.S. CITIES*



**Monthly Average for 12 Months Ending January 2004 Based on 1,000 kWh and 5 MCF, as compiled by CPS.*

five year highlights

(Unaudited)

(Dollars in thousands)

For Year Ended January 31,	2004	2003	2002	2001	2000
FINANCIAL SUMMARY					
Total revenue	$ 1,570,511	$ 1,345,462	$ 1,252,771	$ 1,405,501	$ 1,079,969
Operating & maintenance expenses [1]	955,155	763,722	696,119	769,002	520,915
Payment to City of San Antonio (per financial statements)	206,057	172,235	168,135	185,006	145,474
CAPITAL ASSETS					
Capital assets, net (per Balance Sheet)	4,621,564	4,585,309	4,454,164	4,365,709	4,134,207
Depreciation & depletion expense	228,941	217,037	189,065	217,191	165,249
New construction & net removal costs	269,462	341,977	275,987	249,655	410,801
FUNDING FOR NEW CONSTRUCTION & NET REMOVAL COSTS					
Bond proceeds	173,137	10,687	5,557	66,808	206,573
Commercial paper proceeds	0	13,600	123,600	76,549	0
Repair and replacement account	51,266	262,962	64,405	2,177	151,085
Overhead conversion fund	1,374	5,713	8,939	8,891	7,420
Contributed capital	43,685	49,015	73,486	95,230	45,723
OTHER FINANCIAL DATA					
STP nuclear decommissioning master trust fund assets	211,118	183,291	145,878	119,840	95,493
Repair and replacement account	567,698	413,717	548,303	465,206	330,984
Total assets	6,823,236	6,578,941	6,521,346	6,255,245	5,005,769
Fund net assets	2,829,376	2,751,050	2,664,571	2,416,100	2,048,534
DEBT					
Outstanding					
Bonds	2,622,470	2,499,525	2,589,860	2,668,820	2,730,575
Commercial paper	350,000	350,000	350,000	252,800	134,800
Weighted-Average Interest Rate					
Bonds	5.11%	5.17%	5.32%	5.33%	5.24%
Commercial paper	1.01%	1.11%	1.36%	3.95%	3.69%
Debt Service					
Senior lien bonds [2]	230,250	211,831	212,274	208,567	208,925
Junior lien bonds [3]	2,111	0	0	0	0
Commercial paper	4,125	5,327	8,191	8,182	4,709
Debt Service Coverage - Senior Lien Bonds	2.54x	2.51x	2.64x	3.05x	2.68x
Ratings - Bonds and Commercial Paper					
Fitch - Senior lien bonds	AA+	AA+	AA+	AA+	AA+
- Junior lien bonds	AA+/F1+	-	-	-	-
- Commercial paper	F-1+	F-1+	F-1+	F-1+	F-1+
Moody's - Senior lien bonds	Aa1	Aa1	Aa1	Aa1	Aa1
- Junior lien bonds	Aa2/VMIG 1	-	-	-	-
- Commercial paper	P-1	P-1	P-1	P-1	P-1
Standard & Poor's - Senior lien bonds	AA+	AA+	AA	AA	AA
- Junior lien bonds	AA/A-1+	-	-	-	-
- Commercial paper	A-1+	A-1+	A-1+	A-1+	A-1+
RELIABILITY INDICES					
System Average Interruption Duration Index (SAIDI) (in hours)	0.746	0.582	0.650	1.124	0.728
System Average Interruption Frequency Index (SAIFI)	1.219	0.946	1.005	1.527	1.162

(1) Excludes depreciation expense.
(2) Excludes cash defeasance in 2003 and 2001.
(3) Junior Lien Obligations issued in May 2003 (VRDO).

five year operations review

(Unaudited)

For Year Ended January 31,	2004	2003	2002	2001	2000
OPERATING REVENUE [1] *(in thousands)*					
Electric:					
Residential	$ 591,593	$ 512,164	$ 479,471	$ 516,203	$ 428,450
Commercial and industrial	550,872	430,873	398,563	411,773	353,055
Street lighting	14,036	13,090	12,703	12,786	11,977
Public authorities	70,966	95,843	94,586	105,815	94,475
Sales for resale	20,075	17,876	14,539	15,548	12,581
Off-system sales	27,681	12,333	19,368	54,677	26,499
Unbilled revenue	9,292	40,708	0	0	0
Other	14,933	9,901	9,029	7,612	6,592
Total	$ 1,299,448	$ 1,132,788	$ 1,028,259	$ 1,124,414	$ 933,629
Gas:					
Residential	$ 112,683	$ 84,616	$ 94,443	$ 122,385	$ 59,748
Commercial and industrial	82,988	55,476	64,341	75,888	39,425
Public authorities	13,978	9,123	12,271	14,704	6,694
Unbilled revenue	(6,488)	17,676	0	0	0
Other	1,205	1,814	1,532	1,579	1,153
Total	$ 204,366	$ 168,705	$ 172,587	$ 214,556	$ 107,020
SALES					
Electric *(MWh)*					
Residential	7,380,491	7,248,870	7,053,649	7,180,459	6,492,199
Commercial and industrial	8,485,624	7,732,905	7,454,710	7,284,582	6,928,944
Street lighting	99,457	97,053	102,668	103,428	100,534
Public authorities	1,100,521	1,829,766	1,954,333	2,083,527	2,108,671
Sales for resale	443,519	329,988	352,521	348,717	327,277
Off-system sales	752,019	172,564	326,559	844,436	470,335
Total	18,261,631	17,411,146	17,244,440	17,845,149	16,427,960
Gas *(thousands of MCF)*					
Residential	11,215	12,088	11,540	12,777	10,027
Commercial and industrial	10,151	10,384	10,184	10,574	9,485
Public authorities	1,801	1,786	2,033	2,065	1,762
Total	23,167	24,258	23,757	25,416	21,274
ELECTRIC GENERATION *(MWh)*					
Generation	17,176,881	16,410,007	17,522,040	18,214,197	17,457,003
Energy purchases & other power	1,937,902	2,200,666	597,983	480,894	14,835
Native load: generation & other power	19,114,783	18,610,673	18,120,023	18,695,091	17,471,838
Total power available [2]	20,587,784	20,175,695	20,533,057	22,547,826	20,352,222
Capacity, MW (Gas)	2,831	2,931	2,942	2,942	2,430
Capacity, MW (Coal)	1,425	1,425	1,385	1,385	1,385
Capacity, MW (Nuclear)	700	700	700	700	700
Capacity, MW (Wind)	160	160	160	25	0
ELECTRIC PEAK DEMAND *(MW)*	4,117	3,937	3,860	4,091	3,729
DISTRIBUTION GAS PURCHASES *(MMCF)*	22,946	26,084	23,559	25,905	21,664
NUMBER OF CUSTOMERS [3]					
Electric	602,313	604,108	592,195	578,296	563,127
Gas	306,845	310,316	306,668	305,811	303,871
RESIDENTIAL AVERAGES					
Electric:					
Revenue per customer	$ 1,128.76	$ 978.49	$ 930.36	$ 1,026.56	$ 874.10
kWh per customer	14,082	13,849	13,687	14,280	13,245
Revenue per kWh	8.02¢	7.07¢	6.80¢	7.20¢	6.60¢
Gas:					
Revenue per customer	$ 395.05	$ 295.85	$ 330.97	$ 430.49	$ 211.34
MCF per customer	39.3	42.3	40.4	44.9	35.5
Revenue per MCF	$ 10.05	$ 7.00	$ 8.18	$ 9.58	$ 5.96
NUMBER OF EMPLOYEES	4,103	4,276	4,195	3,994	3,810

(1) Includes unbilled electric and gas revenues for 2004 and 2003, which were first recorded in fiscal year 2003.
(2) Includes joint operating systems generation.
(3) Effective fiscal year 2004, customer count is based upon active contracts. The change affects the comparability between periods and does not necessarily mean a drop in the customer base.

REPORT OF MANAGEMENT

The Board of Trustees is responsible for the audited financial statements but has delegated responsibility for the preparation to Management.

The audited financial statements included in this report were prepared by Management in conformity with generally accepted accounting principles and the statements are presented fairly in all material respects. Management has also prepared the financial information presented elsewhere in the annual report and has ensured that it is consistent with information in the audited financial statements.

City Public Service maintains internal accounting and administrative controls designed to provide reasonable assurance that the financial information is relevant, reliable and accurate and that assets are appropriately accounted for and adequately safeguarded. As part of this process, Management has an internal audit function which assists in evaluating the adequacy and effectiveness of the control structure.

The Board of Trustees is responsible for reviewing and approving the audited financial statements and Management s Discussion and Analysis and, primarily through its Audit Committee, ensures that Management fulfills its responsibilities for financial reporting.

The Audit Committee meets regularly with Management, and with the internal and external auditors, to discuss internal control and reporting issues and to satisfy itself that each party is properly discharging its responsibilities. The Audit Committee reviews the audited financial statements and the external auditors report and considers, for review and approval by the Board, the engagement or reappointment of the external auditors.

CPS external auditors, KPMG LLP, Robert J. Williams, CPA; and Garza, Preis & Co., L.L.C., have audited the financial statements in accordance with generally accepted auditing standards. They considered the company s control structure and performed such tests and other procedures, as they deemed necessary to express an opinion on the fairness of the audited financial statements. The external auditors were given full and free access to the accounting records through CPS Management.

Milton B. Lee
General Manager and CEO

April 26, 2004

V. Gary Schaub
Secretary-Treasurer
Senior Vice President
Financial and Corporate Services

City Public Service of San Antonio, Texas

Basic Financial Statements
Years Ended January 31, 2004 and 2003

(With Independent Auditors' Report Thereon)

Audited Financial Statements – Table of Contents

Management s Discussion and Analysis 25-33

Independent Auditors Report. 34

Balance Sheets 35-36

Statements of Revenues, Expenses and Changes in Fund Net Assets. 37

Statements of Cash Flows 38

Notes to Basic Financial Statements 39-59

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management Discussion and Analysis (MD&A) serves as an introduction to the financial statements of City Public Service (CPS). It is intended to be an objective and easily understandable analysis of significant financial and operating activities and events for the fiscal year ending January 31, 2004 (2004). It also provides an overview of CPS' general financial condition and results of operations for the fiscal year ending January 31, 2003 (2003). This MD&A is in accordance with the Governmental Accounting Standards Board (GASB) Statement No. 34, *Basic Financial Statements – and Management's Discussion and Analysis – for State and Local Governments,* which CPS implemented in fiscal year ending January 31, 2002 (2002). This MD&A should be read in conjunction with the financial statements and accompanying footnotes that follow the MD&A.

Basic Financial Statements

The Balance Sheets present information on CPS' assets and liabilities as of the end of each fiscal year. Assets are separated into current and non-current and reported based in the order of liquidity. Current assets include unrestricted cash and investments, receivables, inventories, prepayments and other current deferred costs. Non-current assets include cash, cash equivalents, investments and interest receivable which have been restricted by state law, ordinances or contracts. Other non-current assets, deferred costs and capital assets are also included in this category. Liabilities are also segregated into current and non-current. Current liabilities include the current maturities of revenue bonds, accounts payable, and other current payables and accrued liabilities. Non-current liabilities include long-term net debt, the South Texas Nuclear Project (STP) decommissioning liability, deferred revenue and other liabilities. The Balance Sheets report fund net assets as the difference between the total assets and total liabilities. The fund net assets are classified as those invested in capital assets, net of related debt; those legally restricted; and those unrestricted and available for operations.

The Statements of Revenues, Expenses and Changes in Fund Net Assets present the revenue and expenses for each fiscal year. Operating results are reported separately from non-operating activities, which primarily relate to financing and investing. Contributed capital is also reported separately as a component of the change in fund net assets. This statement identifies for each fiscal year the amount of revenue generated from sales to cover operating expenses. Operating expenses are presented by major cost categories. Revenues remaining are available to pay debt service; to pay city payment; to finance system additions; and to pay for contingencies.

The Statements of Cash Flows present the cash activity for each fiscal year segregated into operating activities, capital and related financing activities, non-capital financing activities, and investing activities. This statement is prepared using the direct method which reports cash receipts and payments and a reconciliation of operating income to net cash provided by operating activities. The changes in cash balances during the fiscal years are an indicator of CPS' liquidity and financial condition.

Financial Highlights and Significant Accounting Policies

Contributions to construct capital assets flow through the Statements of Revenues, Expenses and Changes in Fund Net Assets and are shown as part of the utility's equity that is invested in capital and other assets. The amount reported for contributed capital was $47.2 million for 2004 as compared with $53.4 million for 2003. Included in contributed capital for 2004 is $3.5 million related to the acquisition of electric facilities at Fort Sam Houston, a major Army post, and Camp Bullis, a U.S. Army training installation, which occurred during 2004. About $25.7 million of the contributed capital amount for this year came from litigation settlements, mainly the Joint Operating Agreement with Texas Genco. L.P., a subsidiary of CenterPoint Energy. The remainder was contributed by customers for utility extensions and services.

Included in contributed capital for 2003 is $4.4 million of contributed capital associated with the acquisition of the electric and natural gas facilities at Brooks City-Base, formerly Brooks Air Force Base. About $31.1 million of the contributed capital amount for 2003 was obtained from litigation settlements.

The excess of assets over liabilities of the utility system is reported as fund net assets. At January 31, 2004, this totaled $2.829 billion as compared with $2.751 billion as of January 31, 2003, and $2.665 billion for January 31, 2002. CPS reports the assets and liabilities accumulated for the employee health and welfare plans and for the Decommissioning Master Trust under GASB Statement No. 14, *The Financial Reporting Entity.* In compliance with the provisions of

GASB 14, CPS has included these component units in its financial statements for external reporting purposes. These assets are legally segregated from CPS and are accounted for separately. In 2004 and 2003, fund net assets include $152.8 million and $122.7 million, respectively, for the employee health and welfare plans. There are no fund net assets associated with the Decommissioning Master Trust since the decommissioning liability equals the Trust assets. In 2002, fund net assets include $131.7 million for the employee health and welfare plans. In addition, CPS' income before contributed capital as a result of inclusion of the health and welfare plans as reported on the Statements of Revenues, Expenses and Changes in Fund Net Assets was $30.0 million higher for 2004 due primarily to a greater change in fair value on the plan investments from the prior year. For 2003 and 2002, income before contributed capital was $8.9 million lower and $7.4 million lower, respectively, as investment earnings from the plans were less than the claims paid.

In 2004, CPS adopted the provisions of GASB Technical Bulletin No. 2003-01, *Disclosure Requirements for Derivatives Not Presented at Fair Value on the Statement of Net Assets.* The adoption of this guidance did not affect CPS' financial position or results of operations. However, it did result in reporting presentation changes that were incorporated into the footnote disclosures for risk management.

Summary of Balance Sheet Information

	January 31,		
	2004	2003	2002
		(In thousands)	
Assets			
Current and other assets	$ 2,201,672	$ 1,993,632	$ 2,067,182
Capital assets, net	4,621,564	4,585,309	4,454,164
Total Assets	6,823,236	6,578,941	6,521,346
Liabilities			
Current liabilities	287,969	276,540	238,194
Long-term liabilities	3,705,891	3,551,351	3,618,581
Total Liabilities	3,993,860	3,827,891	3,856,775
Fund Net Assets			
Invested in capital assets, net of related debt	1,722,770	1,850,944	1,690,076
Restricted	770,767	577,705	722,859
Unrestricted	335,839	322,401	251,636
Fund Net Assets	$ 2,829,376	$ 2,751,050	$ 2,664,571

Summary of Revenues, Expenses and Changes in Fund Net Assets Information

	Years Ended January 31,		Amount	Percentage		Amount	Percentage
	2004	2003	Change	Change	2002	Change	Change
(In thousands)							
Revenue:							
Utility operating	$1,503,814	$1,301,493	$202,321	15.5%	$1,200,846	$100,647	8.4%
Non-operating income, net	66,697	43,969	22,728	51.7%	51,925	(7,956)	-15.3%
Total Revenue	1,570,511	1,345,462	225,049	16.7%	1,252,771	92,691	7.4%
Expenses:							
Depreciation	228,941	217,037	11,904	5.5%	188,999	28,038	14.8%
Decommissioning	24,402	36,647	(12,245)	-33.4%	26,038	10,609	40.7%
Other operating and maintenance	930,753	727,075	203,678	28.0%	670,147	56,928	8.5%
Interest and debt related	149,223	159,420	(10,197)	-6.4%	163,151	(3,731)	-2.3%
Payments to the City of San Antonio	206,057	172,235	33,822	19.6%	163,135	4,100	2.4%
Total Expenses	1,539,376	1,312,414	226,962	17.3%	1,216,470	95,944	7.9%
Income Before Contributed Capital	31,135	33,048	(1,913)	-5.8%	36,301	(3,253)	-9.0%
Contributed capital	47,191	53,431	(6,240)	-11.7%	73,096	(19,665)	-26.9%
Change in Fund Net Assets Before Change in Accounting Policy	78,326	86,479	(8,153)	-9.4%	109,397	(22,918)	-20.9%
Cumulative Effect of Change in Accounting Policy	0	0	0	0.0%	138,074	(139,074)	-100.0%
Change in Fund Net Assets After Change in Accounting Policy	78,326	86,479	(8,153)	-9.4%	248,471	(161,992)	-65.2%
Fund Net Assets - Beginning	2,751,050	2,664,571	86,479	3.2%	2,416,100	248,471	10.3%
Fund Net Assets - Ending	$2,829,376	$2,751,050	$ 78,326	2.8%	$ 2,664,571	$ 86,479	3.2%

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Fund Net Assets - Ending	$2,829,376	$2,751,050	$ 78,326	2.8%	$ 2,664,571	$ 86,479	3.2%

Results of Operations

Electric and gas operating revenue of $1.504 billion for 2004 rose $202.3 million, or 15.5 percent from the prior year, primarily due to higher electric and gas fuel recoveries. Representing about 82.7 percent of CPS' total revenue, electric system operating revenue of $1.299 billion increased 14.7 percent from last year. Revenue from electric fuel recoveries was up $145.5 million due to the higher fuel costs. Revenue from electric base rate sales rose 2.5 percent from last year. Total electric sales of 18.3 billion kWh were 4.9 percent higher, reflecting an increase in off-system sales from 0.173 million MWh in 2003 to 0.752 million MWh in 2004. The number of electric customers totaled 602,313 as of January 2004, an increase of 10,021 from January 2003. Effective February 2003, the customer count methodology was changed from number of bills to number of active contracts. The prior year customer count was restated to reflect active contracts. CPS also recorded an all-time record high peak demand on August 8, 2003 of 4,117 MW. Regulatory recoveries added $50.8 million to total electric revenue and were up significantly from last year. These recoveries represent the pass-through of CPS' charges for utility commission assessments for statewide transmission costs and for Electric Reliability Council Of Texas (ERCOT)-related fees. Unbilled electric operating revenues added $9.3 million to total electric revenue.

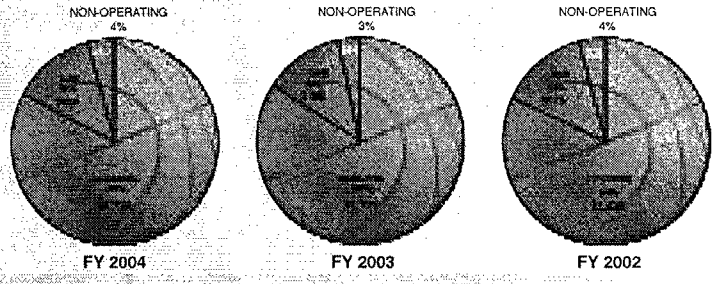
Gas system operating revenue in 2004 totaled $204.4 million, a 21.1 percent increase from the previous fiscal year, and accounted for 13.0 percent of total revenue. The increase was due entirely to greater revenue from gas cost recoveries resulting from the higher average unit cost of gas. Gas unbilled operating revenue reduced total gas revenue by $6.5 million. Based upon active contracts, gas customers at January 2004 totaled 306,845, an increase of 501 from the previous year. Gas sales of 23.2 million MCF were down 4.5 percent from last year, reflecting the milder winter weather this year.

For 2003, electric and gas operating revenue totaled $1.301 billion, an increase of 8.4 percent from the prior year. Electric system operating revenue totaled $1.133 billion and was up 10.2 percent from 2002. Most of the increase was due to higher revenue from electric fuel recoveries and the inclusion of unbilled revenue, which began to be recorded in 2003. Electric sales of 17.4 billion kWh in 2003 were 1.0 percent higher than the previous year. Regulatory recoveries totaled $21.5 million for 2003. Gas system operating revenue in 2003 totaled $168.7 million and decreased 2.2 percent from 2002 due mainly to reduced revenue from gas cost recoveries. Gas sales of 24.3 million MCF rose 2.1 percent from 2002.

Net non-operating income of $66.7 million in 2004 increased by 51.7 percent. The change in fair value recorded on the employee health and welfare investments increased by $39.9 million from last year and accounted for all of the favorable variance in net non-operating income. These assets can be invested in a wider array of securities than CPS internal funds. This increase was partially offset by reduced investment yields on CPS operational funds, which reflected the current market conditions in 2004. Lower investment income and changes in fair value were also recorded for the STP Decommissioning Trust investments.

In 2003, net non-operating income of $44.0 million decreased $8.0 million from the prior year primarily due to lower investment yields from CPS operational funds.

Total Revenue (Dollars in Millions)



Total operating expenses of $1.184 billion in 2004 increased 20.7 percent. All major categories of expenses increased from last year. Electric fuel and purchased power costs of $401.5 million increased by $124.5 million, or 44.9 percent. The average unit price per MWh increased substantially from last year due primarily to higher natural gas prices and reduced nuclear generation. The lower nuclear generation reflected the STP Unit 2 forced outage early in the fiscal year to repair excessive turbine vibration, and the Unit 1 planned refueling outage in the spring and subsequent forced outage during the summer associated with the bottom mounted instrumentation tubes seepage. Both units were operating near full power the second half of 2004, but reflect lower combined year-to-date generation. The reduction in nuclear generation was replaced by more expensive gas and a greater amount of coal generation and purchased power. Total generation and other power requirements were 2.7 percent greater than last year.

Distribution gas costs totaled $132.3 million, an increase of $40.8 million in 2004. The average unit distribution gas cost rose from last year. Natural gas market prices increased during late February 2003 to more than $20 per MCF, reflecting the nation-wide cold spell and the onset of war in the Middle East. CPS employed its hedging tactics and also used lower-cost gas brought out of storage to reduce the effect of the spike in gas prices to its customers. Prices declined during the summer and fall months, but were still much higher than last year on a year-to-date basis. The volume of distribution gas purchases decreased 10.9 percent.

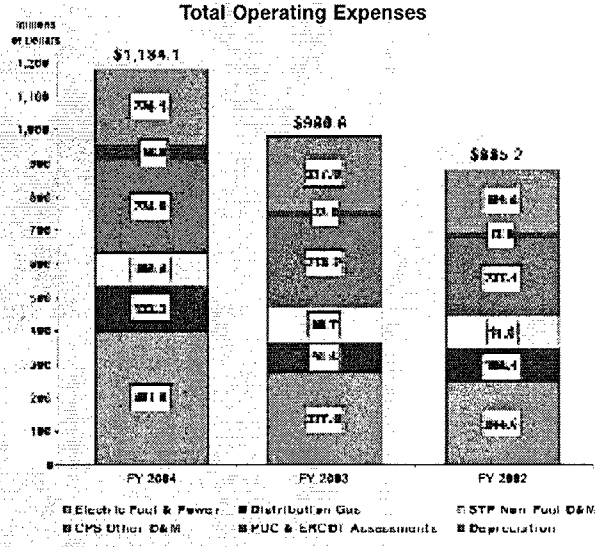
STP nuclear plant non-fuel operating and maintenance expenses, including decommissioning, increased 1.0 percent, totaling $100.6 million in 2004. Higher production maintenance costs this year included activities related to the Unit 1 planned refueling outage in March and April 2003, and its subsequent forced outage throughout the remainder of the spring and summer months. In April, a small seepage was discovered in two of the 58 bottom mounted instrumentation tubes from a routine inspection during refueling of Unit 1. The tubes were inspected and repaired and the unit was returned to service in early August. Approximately $6.7 million was spent on the forced outage and another $5.7 million was related to its planned refueling outage. Other smaller increases were seen in various administrative and general costs. These increases were partially offset by a decrease in non-cash decommissioning expense.

CPS' non-fuel operating and maintenance expenses of $274.9 million in 2004 were essentially the same as the prior year. Labor-related costs and employee benefits were somewhat higher than last year. Higher expenses for electric distribution operating and electric transmission maintenance activities were also incurred. These increases were offset by lower costs for various services, materials and equipment, especially in the areas of modular remodeling, communication and signal items for the Systems Control and Data Acquisition system, wireless and voice systems, and computer service contracts.

Regulatory assessments expense of $45.9 million increased by $23.6 million in 2004, due mainly to greater ERCOT-related costs that were primarily for managing increasing congestion on the statewide grid. Specific charges that contributed to the variance were Out of Merit Energy charges, Out of Merit Replacement Capacity charges and Reliability Must Run service charges. Transmission cost of service net billings assessed by the Public Utility Commission (PUC) of Texas were $1.4 million higher than last year.

Depreciation expense of $228.9 million in 2004 was $11.9 million greater than last year, reflecting the new plant additions during the year subject to depreciation. Some true-ups and adjustments were also recorded at the end of the fiscal year for the Gugert and Salado Street facilities remediation and for other asset classes depreciation charges.

Total Operating Expenses



Interest and debt-related costs of $149.2 million were $10.2 million lower than last year. This year included lower Senior Lien Bond and Tax-Exempt Commercial Paper (TECP) interest costs. The prior year also included debt defeasance costs related to a cash defeasance transaction. In August 2002, CPS legally defeased $144.2 million in certain outstanding revenue bonds with available funds and costs of $7.1 million were incurred related to the transaction. This variance was partially offset by the current year s interest expense on the Junior Lien Variable Rate Demand Obligations (VRDO), which began to be recorded in May 2003. The Allowance for Funds Used During Construction decreased this year, due to the reduction in gross construction expenditures and lower capitalized interest rates reflecting the current interest rate market.

Payments and services to the City of San Antonio (City) in 2004 totaled $206.1 million and were 19.6 percent greater than 2003, reflecting the higher gross revenue subject to City Payment. This was the first fiscal year where the City Payment exceeded $200 million.

Income before contributed capital totaled $31.1 million, a decrease of 5.8 percent. Higher STP non-fuel operating and maintenance expenses and greater depreciation expense were contributing factors. Last year s adjustment for unbilled revenue also contributed to the variance, as last year was the base year for applying the calculation. This year s unbilled revenue reflects only the net change from last year. This was partially offset by higher net non-operating income, primarily from the investments of the employee health and welfare plans, and somewhat greater revenue from electric sales.

After recording $47.2 million in contributed capital, which includes $3.5 million related to the Fort Sam Houston and Camp Bullis acquisitions, the overall change in fund net assets totaled $78.3 million for the year ended January 2004, as compared to $86.5 million for the prior year.

In 2003, operating expenses totaled $980.8 million, an increase of 10.8 percent from 2002. Electric fuel costs, CPS non-fuel operating and maintenance expenses, regulatory assessments and depreciation expense all increased

from the previous year but were partially offset by lower costs for distribution gas and STP nuclear expenses, excluding decommissioning. Electric fuel and purchased power costs of $277.0 million increased by 13.2 percent, due to higher generation requirements and a greater average unit fuel cost per MWh. Distribution gas costs totaled $91.6 million, a decrease of $13.8 million from 2002 due to a lower average unit gas cost. STP non-fuel operating and maintenance expenses, including decommissioning, increased 8.6 percent, totaling $99.7 million. Increases in non-cash decommissioning and employee benefits costs contributed to the variance, which were partially offset by lower production maintenance costs, as 2002 included refuelings outages for both units versus the single planned refueling outage for Unit 2 in 2003. CPS non-fuel operating and maintenance expenses of $273.2 million rose $35.8 million from 2002. These increased expenses included higher labor and related costs, which includes payroll taxes and employee benefits; greater costs for sales promotions, outside services, and property insurance; and costs for various planned power plant overhauls. Regulatory assessments expense of $22.3 million increased by $5.3 million or 31.3 percent from 2002 due to greater net transmission charges incurred by the PUC. Depreciation expense in 2003 totaled $217.0 million, an increase of $28.0 million or 14.8 percent, which reflected the application of updated and slightly higher depreciation rates implemented in 2003.

Interest and debt-related costs in 2003 totaled $159.4 million and were $3.7 million lower than in 2002. Lower revenue bond and TECP interest costs in 2003 were partially offset by the debt defeasance costs related to the cash defeasance transaction. Payments and services to the City totaled $172.2 million in 2003 and were 2.4 percent greater than the prior year, reflecting the higher gross revenue subject to City Payment.

Income before contributed capital for 2003 totaled $33.0 million, a decrease of 9.0 percent from 2002. The decrease in non-operating income, and higher CPS non-fuel operating and maintenance costs and depreciation expense contributed to the variance. After recording $53.4 million in contributed capital, which includes $4.4 million related to the Brooks City-Base acquisition, the overall change in fund net assets totaled $86.5 million in 2003. This compares to the change in fund net assets of $109.4 million for 2002, before including the cumulative effect of change in accounting policy related to the inclusion of the employee health and welfare plans into the 2002 financial statements.

Total assets at January 31, 2004 were $6.823 billion, an increase of $244.3 million from January 31, 2003. CPS Repair and Replacement Account balance increased $153.4 million, as there were greater revenue deposits from operations this year and a lower amount used for construction versus the prior year. Also, increases in cash, cash equivalents and investments and interest receivable of the employee health and welfare plans and the STP decommissioning master trust accounted for $30.5 million and $27.8 million, respectively, of the increase in total assets. Net capital assets increased $36.3 million from the prior year. Prepayments and other current assets rose by $8.7 million and included a prepayment for capital spare parts related to the long-term service agreements for the Arthur von Rosenberg power plant. These increases were partially offset by decreases in other unrestricted cash, cash equivalents and investments of $7.0 million.

Total assets at January 31, 2003 of $6.579 billion increased $57.6 million from January 31, 2002. The inclusion of $58.4 million in unbilled revenue receivable and an increase of $11.9 million in fuel stock contributed to the variance. The higher fuel stock in 2003 was due primarily to a greater coal inventory and natural gas held in storage which began that year. Net capital assets and the cash, cash equivalents and investments of the STP decommissioning trust also increased from 2002. These increases were partially offset by decreases in 2003 in other cash, cash equivalents and investments of approximately $193.0 million from 2002.

CPS' total debt service and other interest requirements of $238.0 million in 2004 were 4.9 percent higher than the previous year. Debt service requirements this period included lower interest costs on revenue bonds and TECP. Also, last year included an additional $7.1 million for the costs for cash defeasance of debt. There was no debt defeasance transaction this year. These decreases were offset by higher scheduled revenue bond principal payments.

In 2003, debt service and other interest requirements of $226.8 million rose 2.0 percent from the previous year. Lower interest costs on revenue bonds and TECP were offset by higher scheduled revenue bond maturities and the costs from the cash defeasance transaction.

Utility Plant

Net capital assets of $4.622 billion at January 31, 2004 increased $36.3 million from last year. Greater plant additions were recorded in the areas of electric transmission and distribution and the gas system. Construction work-in-progress decreased $82.1 million, as more jobs were completed and closed to finished plant this year. Net capital assets of $4.585 billion at January 31, 2003 increased $131.1 million from 2002 and included greater plant additions in electric transmission and distribution and higher construction work-in-progress.

For the year ended January 31, 2004, total expenditures for new construction and net removal costs totaled $269.5 million. Major construction projects and capital expenditures included: 1) initial work on the installation of the four gas-fired generating peaking units, which were purchased last year; 2) underground and overhead electric distribution system initiatives for reliability, service improvements and customer growth; 3) gas system improvements and gas mains, services and extensions; 4) transmission substations and lines construction within the service area; and 5) facility improvements, including initial work on the new Primary Control Center. Actual expenditures for new construction and net removal costs in 2004 were funded from the following sources: $163.3 million from tax-exempt VRDO proceeds; $51.3 million from the Repair and Replacement Account; $43.7 million from contributed capital; $9.8 million from revenue bond proceeds; and $1.4 million from the Overhead Conversion Fund. This funding detail reflects the reimbursement to the Repair and Replacement Account in May 2003 by the VRDO proceeds for prior months construction.

For the year ended January 31, 2003, total expenditures for new construction and net removal costs totaled $342.0 million. Major construction projects and capital expenditures included: 1) the purchase of the four gas-fired generating peaking units; 2) underground and overhead electric distribution system initiatives for reliability, service improvements and customer growth; 3) the purchase of four sets of approximately 135 aluminum railcars each which replaced older steel cars; 4) completion of the BIS project; and 5) facility improvements, including work completed on the Northside Customer Service Center.

CPS Mission Road power plant, with a generating capacity of 100 MW, was officially taken out of service in October 2003. CPS total generating capacity was reduced accordingly.

At January 31, 2004, CPS had $13.3 million in VRDO proceeds remaining in the VRDO Construction Fund and $5.6 million of bond proceeds from last year s revenue bond transaction in the Bond Construction Fund which are available to fund eligible projects and construction for the upcoming year.

Summary of Capital Assets, Net of Depreciation Information

	January 31, 2004	January 31, 2003	Amount Change	Percentage Change	January 31, 2002	Amount Change	Percentage Change
(In thousands)							
Land	$ 67,795	$ 67,527	$ 268	0.40%	$ 67,488	$ 39	0.06%
Buildings and structures	743,119	771,557	(28,438)	-3.69%	789,012	(17,455)	-2.21%
Systems and improvements:							
Generation	1,467,504	1,455,888	11,616	0.80%	1,506,655	(50,767)	-3.37%
Transmission and distribution	1,448,356	1,333,849	114,507	8.58%	1,295,296	38,553	2.98%
Gas	314,782	301,518	13,264	4.40%	298,001	3,517	1.18%
Machinery and equipment	287,496	276,822	10,674	3.86%	267,225	9,597	3.59%
Other	8,441	8,980	(539)	-6.00%	8,802	178	2.02%
Nuclear fuel	35,486	38,496	(3,010)	-7.82%	30,968	7,528	24.31%
Construction in progress	248,585	330,672	(82,087)	-24.82%	190,717	139,955	73.38%
Capital Assets, Net of Depreciation	$ 4,621,564	$ 4,585,309	$ 36,255	0.79%	$ 4,454,164	$ 131,145	2.94%

Financing and Debt Covenants Compliance

The continuing low interest rate environment in 2004 created several refunding and financing opportunities for CPS. In May 2003, CPS issued $250.0 million in VRDOs. These Junior Lien Obligations were issued to provide funds for capital projects. CPS obtained an initial interest rate of 1.2 percent. The rate changes weekly to reflect the variable–rate bond market. These bonds also contain put options, allowing them to be called with short notice if the rates should increase unfavorably to CPS. Of the funding, approximately $111.9 million was directed to reimburse CPS Repair and Replacement Account for prior capital expenditures, and $138.1 million was targeted to fund future capital projects, including a small amount to pay for costs of issuance.

CPS also completed two separate revenue refunding bond transactions in June and July 2003. The first, a forward delivery transaction, was for the sale of $350.5 million of New Series 2003 Bonds at a true interest cost of 3.08 percent to current refund $375.5 million of certain higher-rate, outstanding New Series 1994-A bonds. This transaction resulted in gross cash flow savings of $32.9 million. The settlement date occurred in November 2003. In the second transaction, CPS sold $93.9 million of New Series 2003A Bonds at a true interest cost of 3.67 percent. This advance refunding transaction refunded $96.0 million in certain outstanding New Series 1994-A and 1995 Bonds and resulted in gross cash flow savings of $15.9 million.

In August 2002, CPS sold $576.7 million of New Series 2002 Revenue and Refunding Bonds to refund $445.1 million in certain outstanding New Series Bonds and to reimburse prior construction expenditures in the amount of $150.0 million. The New Series 2002 bonds were sold at a true interest cost of 4.26 percent. Also in August 2002, CPS legally defeased $144.2 million in certain outstanding New Series 1997 Bonds with available funds. Costs of $7.1 million were recorded related to the cash defeasance. The combined gross future cash flow savings from the two transactions totaled $36.1 million.

With respect to all New Series Bonds outstanding, which includes the New Series 2003 and 2003A Bonds mentioned above, the net revenues of CPS electric and gas systems are pledged to the payment of principal and interest thereon. All New Series Bonds are classified as Senior Lien Obligations and the principal and interest thereon shall have a first lien upon the net revenues of the systems. The VRDOs are classified as Junior Lien Obligations. The borrowings from the Junior Lien Obligations are equally and ratably secured by and are payable from the net revenues of the systems, such pledge being subordinate and inferior to the pledge of net revenues securing the Senior Lien Obligations, but prior and superior to the lien on and pledge of the net revenues securing the payment of the Commercial Paper Notes. The total amount outstanding of Senior Lien Obligations was $2.372 billion, $2.500 billion and $2.590 billion, respectively, at January 31, 2004, 2003 and 2002. The total amount outstanding of Junior Lien Obligations was $250.0 million at January 31, 2004. There were no Junior Lien Obligations outstanding at January 31, 2003 and 2002.

CPS maintains its TECP Program to provide tax-exempt financing for various purposes. The program is currently authorized to have Notes outstanding in an amount not to exceed $450.0 million, as amended by the ordinance in June 1997. The current revolving credit agreement, as amended and restated, permits CPS to borrow up to an aggregate amount not to exceed $350.0 million for the purpose of paying amounts due under the TECP Program. To date there have been no borrowings under the credit agreement. The TECP is secured by the net revenues of the systems. Such pledge of net revenues is subordinate and inferior to the pledge securing payment of existing Senior Lien and Junior Lien Obligations and any to be issued in the future. There were no TECP transactions in 2004. The balance of TECP outstanding was $350.0 million at January 31, 2004, 2003 and 2002.

As of January 31, 2004, 2003 and 2002, CPS was in compliance with the terms and provisions of the New Series Bonds (Senior Lien), Variable Rate Demand Obligations (Junior Lien) and TECP ordinances.

Refer to the footnotes to the financial statements for more information on CPS debt covenants.

In early May 2003, in conjunction with the issue of the VRDOs, the three major rating agencies, Fitch Ratings, Moody s Investor Services, Inc. and Standard & Poor s Ratings Services (S&P), reaffirmed CPS excellent debt ratings. Subsequent to fiscal year-end, S&P again affirmed CPS high ratings. A moderate debt burden, strong debt service coverage, competitive rates, strong liquidity, strong financial profile and successful management of a diverse portfolio were some of the factors that S&P recognized in its evaluation of CPS. Similar high ratings have been issued for CPS variable rate debt.

Summary of CPS Bond and Commercial Paper Ratings

	Ratings at January 31, 2004		
	Senior Lien Debt	Junior Lien Debt	TECP
Fitch Ratings	AA+	AA+ / F1+	F-1+
Moody's Investors Service, Inc.	Aa1	Aa2 / VGIM 1	P-1
Standard & Poor's Ratings Services	AA+	AA / A-1+	A-1+

Debt service coverage for the Senior Lien Bonds, in accordance with the ordinances, was 2.54x for 2004 and 2.51x for 2003. Interest rates on bonds and commercial paper declined in 2004 due to the financing strategies and transactions and favorable market conditions. CPS' fund net assets to total debt and fund net assets ratio was 48.8 percent at January 31, 2004, as compared to 49.1 percent at January 31, 2003, and 47.5 percent at January 31, 2002. CPS' operating margin was 21.3 percent for 2004, 24.6 percent for 2003 and 26.3 percent for 2002.

Requests for Information

For more information about CPS, contact Robert G. McCullough, Director of Corporate Communications, at (210) 353-2344 or at P.O. Box 1771, San Antonio, Texas 78296-1771.

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Independent Auditors' Report

The Board of Trustees
City Public Service Board of San Antonio, Texas:

We have audited the accompanying balance sheets of the City Public Service Board of San Antonio, Texas (City Public Service), a component unit of the City of San Antonio, Texas, as of January 31, 2004 and 2003, and the related statements of revenues, expenses, and changes in fund net assets and cash flows for the years then ended. These financial statements are the responsibility of City Public Service's management. Our responsibility is to express an opinion on these financial statements based on our audits. We did not audit the financial statements of City Public Service Employees' Pension Plan in 2004 or 2003 or the financial statements of the City Public Service Disability Income, Group Life Insurance and Group Health Plans (Employee Health and Welfare Plans) in 2004 or 2003. The financial information related to the City Public Service Employees' Pension Plan is included in footnote 8 of the notes to the financial statements. As of January 31, 2004 and 2003, the total assets and net assets, respectively, of the Employee Health and Welfare Plans represent 2% and 5%, respectively, of the total assets and total fund net assets of City Public Service. Those financial statements were audited by other auditors, for the years indicated, whose reports thereon have been furnished to us, and our opinion on the City Public Service financial statements, insofar as it relates to the amounts and disclosures included for the City Public Service Employees' Pension Plan and the City Public Service Employee Health and Welfare Plans is based on the reports of other auditors.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. 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 and the reports of other auditors provide a reasonable basis for our opinion.

In our opinion, based on our audit and the reports of other auditors, the financial statements referred to above present fairly, in all material respects, the financial position of City Public Service as of January 31, 2004 and 2003, and the results of its operations and its cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

The management's discussion and analysis on pages 25 through 33 and the schedule of funding progress in footnote 8 of the notes to the financial statements are not a required part of the basic financial statements, but are supplementary information required by accounting principles generally accepted in the United States of America. We and the other auditors, have applied certain limited procedures, which consisted principally of inquiries of management regarding the methods of measurement and presentation of the supplementary information. However, we, and the other auditors, did not audit the information and express no opinion on it.

KPMG LLP Robert J. Williams CPA Garza, Preis & Co., LLC

March 22, 2004

KPMG LLP, KPMG LLP, a U.S. limited liability partnership, is a member of KPMG International, a Swiss cooperative.

Balance Sheets

	January 31, 2004	2003
Assets:	*(In thousands)*	
Current Assets:		
Cash and cash equivalents *(Note 1 and 2)*	$ 51,532	$ 239,703
Investments *(Note 1 and 2)*	238,813	57,614
Interest receivable	1,864	1,357
Customer accounts receivable, less allowance for doubtful accounts of $18,026 in 2004 and $12,957 in 2003 *(includes unbilled revenue of $61.2 million for 2004 and $58.4 for 2003) (Note 3)*	162,592	151,913
Other receivables	25,403	27,705
Inventories, at average costs -		
Materials and supplies	77,008	77,341
Fossil fuels	34,571	38,415
Prepayments and other	35,652	26,996
Total Current Assets	627,435	621,044
Non-Current Assets:		
Restricted --		
Debt service - *(Note 1 and 2)*		
Cash and cash equivalents	13	21
Capital projects - *(Note 1 and 2)*		
Cash and cash equivalents	0	1
Investments	18,253	17,568
Interest receivable	658	337
Bond ordinance - *(Note 1 and 2)*		
Cash and cash equivalents	0	58,835
Investments	612,556	393,321
Interest receivable	5,433	2,785
Employee health and welfare - *(Note 1 and 2)*		
Cash and cash equivalents	16,528	11,662
Investments	140,348	114,510
Interest receivable	611	769
South Texas Nuclear Project decommissioning master trust - *(Note 1, 2 and 11)*		
Cash and cash equivalents	1	8,830
Investments	208,847	172,637
Interest receivable	2,270	1,824
Project Warm - *(Note 1 and 2)*		
Cash and cash equivalents	402	152
Investments	6,680	7,180
Interest receivable	89	88
Prepaid rent - leaseback *(Note 1 and 14)*	535,972	555,762
Other non-current assets and deferred costs *(Note 1)*	25,576	26,306
Capital assets, net *(Note 1, 4, 11 and 15)*	4,621,564	4,585,309
Total Non-current Assets	6,195,801	5,957,897
Total Assets	$ 6,823,236	$ 6,578,941

	January 31, 2004	2003
Liabilities	*(In thousands)*	
Current Liabilities:		
Current maturities of revenue bonds *(Note 6)*	$ 121,245	$ 100,015
Accounts payable and accrued liabilities *(Note 3)*	162,002	172,327
Employee health and welfare payables *(Notes 1 and 10)*	4,722	4,198
Total Current Liabilities	287,969	276,540
Non-Current Liabilities:		
Long-term debt, net *(Notes 5, 6 and 7)*	2,796,460	2,652,256
South Texas Nuclear Project decommissioning *(Notes 1, 6 and 11)*	211,118	183,291
Customer deposits *(Note 6)*	19,935	23,586
Deferred lease revenue *(Notes 1, 6 and 14)*	611,015	633,575
Other non-current liabilities and deferred credits *(Notes 1 and 6)*	67,363	58,643
Total Non-current Liabilities	3,705,891	3,551,351
Total Liabilities	3,993,860	3,827,891
Fund Net Assets *(Note 1)*		
Invested in capital assets, net of related debt	1,722,770	1,850,944
Restricted		
Debt service	13	21
Bond ordinance	617,989	454,941
Employee health and welfare	152,765	122,743
Unrestricted	335,839	322,401
Total Fund Net Assets	2,829,376	2,751,050
Total Liabilities and Fund Net Assets	$ 6,823,236	$ 6,578,941

See accompanying notes to the basic financial statements

Statements of Revenues, Expenses and Changes in Fund Net Assets

	Years Ended January 31, 2004	2003
	(In thousands)	
Operating Revenue: *(Notes 1 and 5)*		
Electric	$ 1,299,448	$ 1,132,788
Gas	204,366	168,705
Total Operating Revenue	1,503,814	1,301,493
Operating Expenses: *(Notes 1, 8, and 9)*		
Fuel, purchased power and distribution gas	533,806	368,592
Other operating and maintenance	321,211	311,885
Employee health and welfare *(Notes 1 and 10)*	29,885	24,304
Regulatory assessments	45,851	22,294
Depreciation *(Notes 1 and 4)*	228,941	217,037
Decommissioning	24,402	36,647
Total Operating Expenses	1,184,096	980,759
Operating Income	319,718	320,734
Non-operating Income (Expense): *(Note 1)*		
Interest and other income	23,990	29,336
Decommissioning investment income and change in fair value	9,214	21,458
Employee health and welfare investment income and change in fair value	33,493	(6,825)
Interest expense *(Notes 6 and 7)*	(137,891)	(141,786)
Amortization of debt reacquisition, issuance, discount and other costs *(Note 6)*	(14,405)	(17,353)
Allowance for funds used during construction *(Note 1)*	3,073	6,776
Costs for cash defeasance of debt *(Note 6)*	0	(7,057)
Payments to the City of San Antonio	(206,057)	(172,235)
Income Before Contributed Capital	31,135	33,048
Contributed capital *(Notes 1 and 4)*	47,191	53,431
Change in Fund Net Assets	78,326	86,479
Fund Net Assets – Beginning	2,751,050	2,664,571
Fund Net Assets – Ending	$ 2,829,376	$ 2,751,050

See accompanying notes to the basic financial statements

Statements of Cash Flows *(Note 1)*

	Years Ended January 31, 2004	2003
	(In thousands)	
Cash Flows from Operating Activities: *(Note 1)*		
Cash received from customers	$ 1,492,360	$ 1,214,815
Cash payments to suppliers for goods and services	(760,121)	(564,839)
Cash payments to employees for service	(156,829)	(150,937)
Net Cash Provided by Operating Activities	575,410	499,039
Cash Flows from Capital and Related Financing Activities:		
Cash paid for additions to utility plant and net removal costs *(Notes 1 and 4)*	(260,792)	(329,462)
Cash paid for nuclear fuel purchases *(Notes 1 and 4)*	(10,940)	(21,537)
Contributions in aid of construction *(Notes 1 and 4)*	40,274	49,015
Proceeds from issuance of revenue bonds *(Note 6)*	204,454	97,270
Premium received from revenue bonds issued *(Note 6)*	48,645	56,803
Principal payments on revenue bonds and cash defeasance of debt *(Note 6)*	(100,657)	(221,980)
Interest paid *(Notes 6 and 7)*	(137,891)	(141,786)
Debt issue and cash defeasance costs paid *(Notes 6 and 7)*	(1,983)	(8,883)
Net Cash (Used) by Capital and Related Financing Activities	(218,890)	(520,560)
Cash Flows from Non-capital Financing Activities:		
Cash payments to the City of San Antonio	(205,080)	(169,937)
Net Cash (Used) by Non-capital Financing Activities	(205,080)	(169,937)
Cash Flows from Investing Activities: *(Note 2)*		
Purchases of investments	(987,983)	(754,724)
Proceeds from sales and maturities of investments	576,641	903,028
Net cash increase in South Texas Project decommissioning master trust assets	(27,442)	(7,690)
Net cash increase in assets held for employee health and welfare	7,813	4,057
Interest and other income	28,803	31,361
Net Cash (Used) Provided by Investing Activities	(402,168)	176,032
Net increase (decrease) in Cash and Cash Equivalents	(250,728)	(15,426)
Cash and Cash Equivalents at Beginning of Period *(Note 1)*	319,204	334,630
Cash and Cash Equivalents at End of Period	$ 68,476	$ 319,204
Reconciliation of Operating Income to Net Cash Provided by Operating Activities		
Cash Flows from Operating Activities:		
Operating income	$ 319,718	$ 320,734
Non cash Items Included -		
Depreciation and amortization expense *(Note 4)*	228,941	217,037
Nuclear fuel amortization *(Note 4)*	13,950	14,009
Allowance for doubtful accounts	5,069	6,595
Changes in current assets and liabilities:		
(Increase) decrease in customer accounts receivable, net	(15,748)	(80,300)
(Increase) decrease in other receivables	2,302	(8,851)
(Increase) decrease in materials and supplies	333	(3,257)
(Increase) decrease in fossil fuels	3,844	(11,889)
(Increase) decrease in prepayments and other	(8,656)	231
Increase (decrease) in accounts payable and accrued liabilities	(10,914)	13,995
Changes in non-current and other assets and liabilities:		
(Increase) decrease in other non-current assets and deferred costs	574	561
Increase (decrease) in customer service deposits payable	(3,651)	(4,683)
Increase (decrease) in South Texas Nuclear Project decommissioning liability	27,827	37,413
Increase (decrease) in employee health and welfare liability	524	252
Increase (decrease) in non-current and other liabilities	11,297	(2,808)
Net Cash Provided by Operating Activities	$ 575,410	$ 499,039

See accompanying notes to the basic financial statements

Notes To Basic Financial Statements
January 31, 2004 and 2003

1. Summary of Significant Accounting Policies

Reporting Entity — City Public Service Board of San Antonio (CPS), a municipal utility owned by the City of San Antonio (City), provides electricity and natural gas to San Antonio and surrounding areas. As a municipal utility, CPS is exempt from payment of income taxes, state franchise and sales taxes, and real and personal property taxes in Texas. CPS provides certain payments and benefits to the City as required by bond ordinances. As a discretely presented component unit of the City, the financial statements of CPS are included in the annual financial reports of the City.

In the evaluation of how to define CPS for financial reporting purposes, management considered all potential component units. The decision to include a potential component unit in the reporting entity was made by applying the criteria set forth in the Governmental Accounting Standards Board (GASB) Statement No. 14, *The Reporting Entity.* The financial reporting entity consists of CPS and certain component units which are legally separate entities, but for which CPS is financially accountable.

The relationship among the following component units and CPS meet the criteria, as set forth in GASB Statement No. 14, for inclusion in the reporting entity and is such that their financial statements are blended with those of CPS:

South Texas Nuclear Project Decommissioning
Master Trust - see Note 11.

City Public Service Disability Income,
Group Life Insurance and Group Health Plans - see Note 10.

Basis of Accounting — The financial statements of CPS are presented in accordance with accounting principles generally accepted in the United States of America for proprietary funds of governmental entities. CPS complies with all applicable pronouncements of GASB. In accordance with GASB Statement No. 20, *Accounting and Financial Reporting for Proprietary Funds and Other Governmental Entities That Use Proprietary Fund Accounting,* CPS has elected not to follow the pronouncements of the Financial Accounting Standards Board (FASB) issued after November 30, 1989.

In accordance with the utility systems revenue bond ordinance, CPS has adopted the uniform system of accounts prescribed by the National Association of Regulatory Utility Commissioners (NARUC). The financial statements are presented using the economic resources measurement focus and the accrual basis of accounting.

Fiscal Year — The fiscal year ended January 31, 2004, is referred to herein as 2004; the fiscal years ended January 31, 2003, January 31, 2002, and January 31, 2001, are referred to herein as 2003, 2002, and 2001, respectively.

Revenue and Expenses — Revenue is recorded when earned. Customers' meters are read and bills are rendered monthly based on billing cycles. Rate schedules include fuel and gas cost adjustment clauses that permit recovery of fuel and gas costs in the month incurred. In 2004 and in 2003, CPS recorded unbilled revenue as earned based upon an extrapolation of customer usage from the prior year, over the days since the last meter read, on a customer by customer basis. The amount of unbilled revenue receivable recorded was $61.2 million in 2004 and $58.4 million in 2003.

CPS' fuel cost adjustment clause permits recovery of regulatory assessments. Beginning in March 2000, CPS began recovering assessments from the Public Utility Commission (PUC) of Texas for transmission access charges and from the Texas Independent System Operator, also known as the Electric Reliability Council of Texas (ERCOT), for its operating costs and other charges applicable to CPS as a wholesale provider of power to other utilities.

Operating revenue includes receipts from energy sales and miscellaneous revenue related to the electric and gas systems operations. Miscellaneous revenue includes late payment fees, rental income, jobbing and contract work, ancillary services, and merchandise sales. Operating expenses include those expenses that result from the ongoing operations of the electric and gas systems.

Non-operating revenue consists primarily of investment income, including fair value adjustments. The amortization of net gains from the lease/leaseback and the sale of water rights in prior years are also included. Some miscellaneous income from renting general property and miscellaneous service is also recorded as non-operating when it is not directly identified with the electric or gas systems.

Capital Assets — The costs of capital asset additions and replacements of capital assets identified as major components, or property units, are capitalized. Maintenance and replacements of minor items are charged to operating expenses. The cost of depreciable plant retired is eliminated from the plant accounts and such costs plus removal costs less salvage are charged to accumulated depreciation.

Utility plant is stated at the cost of construction, including expenditures for: contracted services; direct equipment, material, and labor; indirect costs, including general engineering, labor, equipment, and material overheads; and an allowance for funds used during construction (AFUDC). CPS computes AFUDC using rates, which approximate the cost of borrowed funds, or the short-term investment rate for other funds used for construction. AFUDC is applied to projects estimated to require 30 days or more to complete.

As of February 1, 2000, proceeds from customers and certain litigation settlements to partially fund construction expenditures are reported in the Statements of Revenues, Expenses and Changes in Fund Net Assets as increases in fund net assets in accordance with the requirements of GASB Statement No. 33.

CPS computes depreciation using the straight-line method over the estimated service lives of the depreciable property using specifically identified service lives for each asset type. In 2003, a depreciation study was conducted to determine if existing depreciation rates remained applicable to the depreciable property groups. New rates were applied beginning in 2003. Total depreciation and depletion, as a percentage of total depreciable assets net of nuclear fuel were 3.40 percent in 2004 and 3.36 percent in 2003.

The estimated useful lives of capital assets are as follows:

	2004	2003
Buildings and structures	15-60 years	15-60 years
Systems and improvements:		
Generation	8-45 years	8-45 years
Transmission and distribution	20-55 years	20-55 years
Gas	50-65 years	50-65 years
Machinery and equipment	4-30 years	4-30 years
Lignite mineral rights and other	20-40 years	20-40 years
Nuclear fuel	1-2 years	1-2 years

Unrestricted and Restricted Cash, Cash Equivalents and Investments — CPS investments with a maturity date within one year of the purchase date are reported at amortized cost, which approximates fair value. Amortization of premium and accretion of discount are recorded over the terms of the investments that mature within one year. CPS investments with a maturity date of one year or longer from the purchase date are accounted for using fair value. Fair value is determined by using generally accepted financial reporting services and publications and approved dealers and brokers as necessary. The specific identification method is used to determine cost in computing gain or loss on sales of securities.

CPS reports all South Texas Nuclear Project (STP) Decommissioning Master Trust investments and employee health and welfare investments at fair value.

Restricted funds are generally for uses other than current operations. They are designated by law, ordinance or contract to acquire or construct non-current assets. Funds consist primarily of unspent bond issue or commercial paper proceeds, debt service required for the New Series Bonds, and funds for future construction or contingencies. This category also includes customer assistance programs where proceeds are received from outside parties. The STP Decommissioning Master Trust assets and CPS employee health and welfare plans assets are also considered restricted.

The CPS Board of Trustees authorized that Repair and Replacement Account funds be designated for converting overhead electric facilities to underground. One percent of the prior fiscal year s electric revenue from cities served by CPS is appropriated for this program. This is included with the assets restricted by bond ordinance.

Other Non-Current Assets and Deferred Costs — In June 2000, CPS entered into a lease/leaseback transaction with Unicom Corporation (Unicom). The long-term portion of prepaid rent related to this transaction was recorded as a deferred cost in 2001. In addition, $12.3 million, less expenses of $350 thousand, was paid to the City of San Antonio, in accordance with the New Series Bond Ordinance (see Note 5), for its 14 percent share of the net benefit from the transaction. This is recorded as a prepaid item and is being amortized over the life of the lease. See note 14 for more information.

Non-current assets include unamortized debt issuance expenses, which are amortized over the shorter of the life of the refunding or refunded bonds. Other assets include the long-term receivable from the San Antonio Water System for the sale of water rights in fiscal year 2000.

Non-current deferred costs also include a Department of Energy (DOE) special assessment fee for decommissioning of U.S. nuclear fuel enrichment facilities. CPS recorded this in fiscal year 1994 to be amortized over a 15-year period to nuclear fuel expense.

Other Non-Current Liabilities and Deferred Credits — The long-term portion of the deferred revenue associated with the lease of the J.K. Spruce Plant was recorded as a deferred credit and is being amortized over the life of the lease. See note 14 for more information.

Other liabilities and deferred credits include the STP decommissioning liability, customer service deposits, advance payments from customers for construction and the DOE special assessments. See "Other Non-Current Assets and Deferred Costs". The long-term portion of the payable to the Greater Kelly Development Authority for the purchase of electric and gas properties in fiscal year 2000 has also been recorded with other liabilities.

Statements of Cash Flows — For purposes of reporting cash flows, CPS considers all highly liquid debt instruments purchased with a maturity of approximately three months or less to be cash equivalents.

The following represent non-cash transactions in 2004 and 2003 not reported on the Statements of Cash Flows:

There was a non-cash capital and related financing activity in 2004 related to the acquisition of utility infrastructure facilities from the military through Ft. Sam Houston and Camp Bullis. As of January 2004, CPS reported contributed capital of $3.5 million for this acquisition. Other non-cash contributed capital totaled $3.4 million.

There was a non-cash capital and related financing activity in 2003 related to the acquisition of utility infrastructure facilities from the military through Brooks City-Base under the Brooks Development Agency. As of January 2003, CPS reported contributed capital of $4.4 million for this acquisition.

In 2004, there were two separate non-cash capital and related financing activities. In July 2003, a deposit was made to an escrow of $104 million directly from bond proceeds to refund $96 million in revenue bonds. In November 2003, a deposit was made to an escrow of $386 million directly from bond proceeds to refund $375 million in revenue bonds.

In 2003, there was also a non-cash capital and related financing activity related to the deposit to an escrow of $479 million directly from bond proceeds to refund $445 million in revenue bonds.

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 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.

2. Cash, Cash Equivalents and Investments

CPS cash deposits at January 31, 2004 and 2003 were entirely insured by federal depository insurance or collateralized by banks for the account of CPS. For deposits that were collateralized, the securities were U.S. Government or Government Agency or U.S. Government guaranteed obligations held in book entry form by the Federal Reserve Bank in CPS name.

CPS allowable investments as defined by CPS Board Resolution and Policy, Bond Ordinances, Tax-Exempt Commercial Paper (TECP) Ordinance and State law include U.S. Government or Government Agency or U.S. Government guaranteed obligations; collateralized mortgage obligations issued by the U.S.; fully secured certificates of deposit issued by a state, national bank, or savings bank domiciled in the State of Texas; direct repurchase agreements; reverse repurchase agreements; defined bankers acceptances and commercial paper; no-load money market mutual funds; and other types of specific secured or guaranteed investments.

CPS investments in the STP Decommissioning Master Trust are held by an independent trustee. Trust investments are limited to U.S. Government or Government Agency or U.S. Government guaranteed obligations by CPS Board Resolution and Policy, Trust Agreement and State law. These investments are subject to market risk and their market value will vary as interest rates fluctuate. This could affect the value at which these securities are recorded.

Investments in the employee health and welfare plans are held by an independent trustee. These investments are limited to those authorized by the plans Administrative Committees, the Trust Agreements and State law. These investments are subject to market risk and their market value will vary as interest rates fluctuate. This could affect the value at which these securities are recorded. These investment policies follow the "prudent man" concept.

Cash, Cash Equivalents and Investments

	January 31, 2004	January 31, 2003
	(In thousands)	
Cash and Cash Equivalents:		
CPS unrestricted and restricted	$ 51,947	$ 298,712
STP Decommissioning Master Trust - restricted	1	8,830
Employee health and welfare - restricted	16,528	11,662
Total Cash and Cash Equivalents	68,476	319,204
Investments:		
CPS unrestricted and restricted	924,789	773,960
STP Decommissioning Master Trust - restricted	208,848	181,467
Employee health and welfare - restricted	156,876	126,172
Total Cash Equivalents and Investments	1,290,513	1,081,599
Less: Investments with original maturities of less than ninety days included in cash equivalents:		
CPS unrestricted and restricted	48,487	298,277
STP Decommissioning Master Trust - restricted	1	8,830
Employee health and welfare - restricted	16,528	11,662
Total Cash Equivalents	65,016	318,769
Total Cash, Cash Equivalents and Investments	$ 1,293,973	$ 1,082,034
Unrestricted:		
Cash and cash equivalents	$ 51,532	$ 239,703
Investments	238,813	57,614
Total Unrestricted	290,345	297,317
Restricted:		
CPS:		
Cash and cash equivalents	415	59,009
Investments	637,489	418,069
Total CPS	637,904	477,078
STP Decommissioning Master Trust - restricted:		
Cash and cash equivalents	1	8,830
Investments	208,847	172,637
Total STP Decommissioning Master Trust	208,848	181,467
Employee health and welfare:		
Cash and cash equivalents	16,528	11,662
Investments	140,348	114,510
Total Employee Health and Welfare	156,876	126,172
Total Cash, Cash Equivalents and Investments	$ 1,293,973	$ 1,082,034
Cash and Cash Equivalents:		
Petty Cash Funds on Hand	$ 135	$ 117
Bond paying agent - debt service	13	0
Deposits with Financial Institutions:		
Unrestricted CPS deposits	2,910	165
Restricted CPS deposits:		
Capital projects	0	1
Project Warm	402	152
Total Restricted Deposits	402	153
Total Deposits with Financial Institutions	3,312	318
Investments with Original Maturities of Less Than Ninety Days:		
CPS unrestricted	48,487	239,421
CPS restricted	0	58,856
STP Decommissioning Master Trust - restricted	1	8,830
Employee health and welfare - restricted	16,528	11,662
Total Cash Equivalents	65,016	318,769
Total Cash and Cash Equivalents	$ 68,476	$ 319,204

Deposits with financial institutions are classified into three categories of custodial risk based upon the following:

Category	Description
1	Deposits insured by the FDIC or collateralized with securities held by CPS or CPS' agent in CPS' name.
2	Deposits collateralized by securities held by the pledging bank's agent in CPS' name.
3	Deposits uncollateralized which include deposits collateralized by securities held by the pledging financial institution or by its trust department or agent but not in CPS' name.

Accordingly, deposits of CPS are categorized by custodial risk as follows:

(In thousands) Deposits with Financial Institutions	Carrying Amounts	Bank Balance	Category 1	Category 2	Category 3
January 31, 2004	$ 3,312	$ 11,720	$ 11,720		
January 31, 2003	$ 318	$ 7,939	$ 7,939		

Investments are classified into three categories of custodial risk based upon the following:

Category	Description
1	Includes investments that are insured or registered, or for which the securities are held by CPS or CPS' agent in CPS' name.
2	Includes uninsured and unregistered investments for which the securities are held by the counterparty's trust department or agent in CPS' name.
3	Includes uninsured and unregistered investments for which the securities are held by the counterparty or by its trust department or agent but not in CPS' name.

Accordingly, the investments of CPS are categorized below to give an indication of the custodial level of risk assumed at January 31, 2004 and 2003.

January 31, 2004

(In thousands) Total Investments By Category	Category 1	Category 2	Category 3	Carrying Amounts	Fair Value
CPS Investments:					
U.S. Treasury & Government Agency Securities	$924,789			$ 924,789	$ 925,228
South Texas Nuclear Project Decommissioning Master Trust:					
U.S. Treasury & Government Agency Securities	$208,848			$ 208,848	$ 208,848
Employee Health and Welfare:					
Corporate Bonds	$ 19,817			$ 19,817	$ 19,817
Common Stock	88,841			88,841	88,841
U.S. Treasury & Government Agency Securities	22,729			22,729	22,729
Global Bonds	8,961			8,961	8,961
Total Health and Welfare Investments Categorized	$140,348			140,348	140,348
Investments not Categorized:					
Money Market Mutual Fund				16,528	16,528
Total Employee Health and Welfare Funds				$ 156,876	$ 156,876

January 31, 2003

(In thousands) Total Investments By Category	Category 1	2	3	Carrying Amounts	Fair Value
CPS Investments:					
U.S. Treasury & Government Agency Securities	$773,960			$773,960	$774,248
South Texas Nuclear Project Decommissioning Master Trust:					
U.S. Treasury & Government Agency Securities	$181,467			$181,467	$181,467
Employee Health and Welfare:					
Corporate Bonds	$ 19,951			$ 19,951	$ 19,951
Common Stock	56,976			56,976	56,976
U.S. Treasury & Government Agency Securities	30,030			30,030	30,030
Global Bonds	7,553			7,553	7,553
Total Health and Welfare Investments Categorized	$114,510			114,510	114,510
Investments not Categorized:					
Money Market Mutual Fund				11,662	11,662
Total Employee Health and Welfare Funds				$126,172	$126,172

As reported in the two preceding tables, Money Market Mutual Fund investments are not categorized as they do not exist in book or physical form.

3. Disaggregation of Receivables and Payables

Receivables -

Net customer accounts receivable as of January 31, 2004 included $61.2 million for unbilled revenue receivables and $101.4 million for billed utility services. Miscellaneous receivables as of January 31, 2004 included $12.4 million for the receivable related to the Joint Operating Agreement with Texas Genco, L.P., $1.0 million for regulatory related receivables, and $12.0 million for other miscellaneous receivables. There are no receivables expected to take longer than one year to collect.

At January 31, 2003, net customer accounts receivable included $58.4 million for unbilled revenue receivables and $93.5 million for billed utility services. Miscellaneous receivables as of January 31, 2003 included $10.8 million for the receivable related to the Joint Operating Agreement with Texas Genco, L.P., $4.5 million for regulatory related receivables, and $12.4 million for other miscellaneous receivables.

Payables -

At January 31, 2004, accounts payable and accrued liabilities included $86.0 million related to standard operating supplier and vendor payables, including fuels payable, $29.3 million to employee related payables, $22.6 million to the current portion of lease deferred revenue, and $24.1 million to other miscellaneous payables and accrued liabilities.

At January 31, 2003, accounts payable and accrued liabilities included $103.3 million related to standard operating supplier and vendor payables, including fuels payable, $27.0 million to employee related payables, $22.6 million to the current portion of lease deferred revenue, and $19.4 million to other miscellaneous payables and accrued liabilities.

4. Capital Assets

Capital asset activity for the years ended January 31, 2004 and January 31, 2003 was as follows:

(In thousands)	Balance 02-01-2003	Additions Increases	Transfers In/(Out)	Reductions Decreases	Balance 01-31-2004
Non-Depreciable Assets:					
Land	$ 54,928	$ 268	$ 0	$ 0	$ 55,196
Land held for future use	12,599	0	(12,599)		0
Nonutility property - land	0		12,599	0	12,599
Construction-in-progress	330,672	230,420	(312,507)	0	248,585
Total Non-Depreciable Assets	398,199	230,688	(312,507)	0	316,380
Depreciable Assets:					
Electric plant	5,511,565	26,270	251,609	56,634	5,732,810
Gas plant	452,528	2,119	21,135	83	475,699
General plant	468,029	6,444	39,763	13,242	500,994
Utility property leased	18,785	0	0	0	18,785
Nuclear fuel	291,439	10,940	0	0	302,379
Total Depreciable Assets	6,742,346	45,773	312,507	69,959	7,030,667
Accumulated Depreciation, Depletion and Amortization:					
Electric	(2,040,601)	(187,176)	0	(59,219)	(2,168,558)
Gas	(150,999)	(10,038)	0	(148)	(160,889)
General	(110,423)	(31,661)	0	(13,277)	(128,807)
Utility property leased	(270)	(66)	0	0	(336)
Nuclear fuel	(252,943)	(13,950)	0	0	(266,893)
Total	(2,555,236)	(242,891)	0	(72,644)	(2,725,483)
Depreciable Assets, Net	4,187,110	(197,118)	312,507	(2,685)	4,305,184
Capital Assets, Net	$4,585,309	$ 33,570	$ 0	$ (2,685)	$4,621,564

Cash paid for additions, net removal costs and nuclear fuel was $271,732, non-cash AFUDC was $3,073, and contributed capital was $6,917 for a total of $281,722. Included in the total are $5,261 in net removal costs. Depreciation, depletion and amortization totaled $242,891

Included in electric plant is the Mission Road generation plant that was taken out of service on October 1, 2003 and is fully depreciated.

CPS' original intention for the land classified in 2003 as "land held for future use" was to mine lignite from the land to be used as an alternative fuel. It was subsequently decided that CPS would not mine the minerals and the land has been reclassified to "non-utility property".

(In thousands)	Balance 02-01-2002	Additions Increases	Transfers In/(Out)	Reductions Decreases	Balance 01-31-2003
Non-Depreciable Assets:					
Land	$ 54,889	$ 40	$ 0	$ 1	$ 54,928
Land held for future use	12,599	0	0	0	12,599
Construction-in-progress	190,717	279,894	(139,939)	0	330,672
Total Non-Depreciable Assets	258,205	279,934	(139,939)	1	398,199
Depreciable Assets:					
Electric plant	5,408,467	40,123	95,378	32,403	5,511,565
Gas plant	440,397	6,354	5,802	25	452,528
General plant	451,876	12,850	38,759	35,456	468,029
Utility property leased	18,785	0	0	0	18,785
Nuclear fuel	269,902	21,537	0	0	291,439
Total Depreciable Assets	6,589,427	80,864	139,939	67,884	6,742,346
Accumulated Depreciation, Depletion and Amortization:					
Electric	(1,894,718)	(179,246)	0	(33,363)	(2,040,601)
Gas	(142,386)	(8,870)	0	(257)	(150,999)
General	(117,226)	(28,855)	0	(35,658)	(110,423)
Utility property leased	(204)	(66)	0	0	(270)
Nuclear fuel	(238,934)	(14,009)	0	0	(252,943)
Total	(2,393,468)	(231,046)	0	(69,278)	(2,555,236)
Depreciable Assets, Net	4,195,959	(150,182)	139,939	(1,394)	4,187,110
Capital Assets, Net	$4,454,164	$129,752	$ 0	$ (1,393)	$4,585,309

Cash paid for additions, net removal costs and nuclear fuel was $350,999, non-cash AFUDC was $6,777, and contributed capital was $4,416 for a total of $362,192. Depreciation, depletion and amortization totaled $231,046.

5. Revenue Bond and Commercial Paper Ordinances Requirements

As of January 31, 2004, the bond ordinances for New Series Bonds issued on and after August 6, 1992 contain, among others, the following provisions:

Revenue deposited in CPS General Account shall be pledged and appropriated to be used in the following priority: (a) for maintenance and operating expenses of the electric and gas systems (Systems), (b) for payments of the New Series Bonds, (c) for the payment of any obligations inferior in lien to the New Series Bonds which may be issued, (d) for an amount equal to six percent of the gross revenue of the Systems to be deposited in the Repair and Replacement Account, (e) for cash payments and benefits to the City not to exceed 14 percent of the gross revenue of the Systems, and (f) any remaining net revenues in the General Account to the Repair and Replacement Account.

The maximum amount in cash to be transferred or credited to the General Fund of the City from the net revenues of the Systems during any fiscal year shall not exceed 14 percent of the gross revenues of the Systems less the value of gas and electric services of the Systems used by the City for municipal purposes and the amounts expended during the fiscal year for additions to the street lighting system. The percentage of gross revenues of the Systems to be paid over or credited to the General Fund of the City each fiscal year shall be determined (within the 14 percent limitation) by the governing body of the City.

The net revenues of the Systems are pledged to the payment of principal of and interest on the New Series Bonds, which are classified as Senior Lien Obligations. All New Series Bonds and the interest thereon shall have a first lien upon the net revenues of the Systems.

The Junior Lien Obligations (Variable Rate Demand Obligations) are special obligations of the City payable solely from and equally and ratably secured by a junior lien on and pledge of the net revenues of the Systems, subject and subordinate to liens and pledges securing the outstanding Senior Lien Obligations and any additional Senior Lien Obligations hereafter issued, and superior to the pledge and lien securing the currently outstanding Commercial Paper Obligations, all as fully set forth in the Ordinance.

The City agrees that it will at all times maintain rates and charges for the sale of electric energy, gas or other services furnished, provided and supplied by the Systems to the City and all other consumers which shall be reasonable and nondiscriminatory and which will produce income and revenues sufficient to pay:

(a) all maintenance and operating expenses, depreciation, replacement and betterment expenses, and other costs as may be required by Chapter 1502, as amended, Texas Government Code;

(b) the interest on and principal of all Parity Bonds, as defined in the New Series Bond Ordinances, as and when the same shall become due, and for the establishment and maintenance of the funds and accounts created for the payment and security of the Parity Bonds;

(c) the interest on and principal of the Prior Lien Bonds, including the Junior Lien Obligations and any Additional Junior Lien Obligations hereafter issued (all as defined in the New Series Bond Ordinances), as and when the same shall become due, and for the establishment and maintenance of the funds and accounts created for the payment and security of the Junior Lien Obligations and any Additional Junior Lien Obligations.

(d) to the extent the same are reasonably anticipated to be paid with available revenues (as defined in the ordinance authorizing the Commercial Paper), the interest on and principal of all Notes (as defined in said ordinance), and the Credit Agreement (as defined in said ordinance); and

(e) a legal debt or obligation of the Systems as and when the same shall become due.

As of January 31, 2004, the TECP Ordinance contains, among others, the following provisions:

To secure the payment of TECP principal and interest, a pledge is made of:

(a) proceeds from (1) the sale of bonds and additional notes issued for such purposes, and (2) the sale of TECP;

(b) TECP proceeds will be used for authorized purposes; and

(c) the net revenues of the Systems, after payment on New Series Bond requirements and Junior Lien Obligations, pledged to the payment on TECP.

As of January 31, 2004, CPS was in compliance with the terms of the New Series Bonds, the Junior Lien Obligations and the TECP ordinances.

6. Revenue Bonds and Other Long-Term Liabilities

In May 2003, CPS issued $250.0 million of variable rate Junior Lien Revenue Bonds. The bonds were issued initially in a weekly interest mode at par value. Of the proceeds, approximately $100 million was issued to reimburse the Repair and Replacement account for prior capital improvements. The mode for the Junior Lien Revenue Bonds or any portion thereof may be converted to a different mode, or to an auction rate or term rate with an interest rate period of different duration, at the direction of the City. Following such a conversion, the Junior Lien Revenue Bonds or portion thereof, will bear interest at the corresponding daily rate, weekly rate, auction rate, commercial paper rate, term rate or fixed rate.

In June 2003, CPS entered into a Forward Delivery Bond Purchase Agreement to issue $350.5 million of New Series 2003 Refunding Bonds in November 2003. The bonds sold at a premium of $37.6 million were issued to refund $375.5 million of 1994–A New Series Bonds. The refunding transaction resulted in cash flow savings of $32.9 million, which equated to a present value savings of $24.0 million, or 6.39 percent of the par amount of refunded bonds. This transaction resulted in a loss for accounting purposes of $10.6 million, which has been deferred and will be amortized over the shorter of the life of the refunded or refunding bonds.

In July 2003, CPS issued $93.9 million of New Series 2003A Revenue Refunding Bonds. The bonds were sold at a premium of $11.0 million and were issued to advance refund $24.4 million of 1994-A New Series Bonds and $71.6 million of 1995 New Series Bonds. The refunding transaction resulted in cash flow savings of $15.9 million, which equated to a present value savings of $5.8 million, or 6.09 percent of the par amount of refunded bonds. This transaction resulted in a loss for accounting purposes of $7.9 million, which has been deferred and will be amortized over the shorter of the life of the refunded or refunding bonds.

In August 2002, $144.2 million par value of 1997 Revenue and Refunding Bonds were legally defeased with cash. The net accounting loss of $7.1 million reported included $149.7 million paid for the actual defeasance, less the par value of the debt, plus unamortized reacquisition and bond issue costs net of float forward agreement proceeds of $1.6 million.

In September 2002, CPS issued $576.7 million of Revenue and Refunding Bonds to refund $445.1 million in certain outstanding New Series Bonds and to reimburse prior construction expenditures of $150.0 million. The bonds were sold at a combined net premium of $56.8 million.

The refunding bonds were issued to current refund $48.7 million of 1992 New Series Bonds and advance refund $396.3 million of other New Series Bonds. The refunding transaction resulted in cash flow savings of $24.1 million, which equated to a present value savings of $18.1 million, or 4.06 percent of the par amount of refunded bonds. This transaction resulted in a loss for accounting purposes of $34.4 million, which has been deferred and will be amortized over the shorter of the life of the refunded or refunding bonds.

A summary of revenue bonds is as follows:

Maturities	Weighted-Average Yield on Outstanding Bonds at January 31, 2004	January 31, 2004	January 31, 2003
		(In thousands)	
Tax-Exempt New Series			
Bonds, 1992-2003, 2005-2021	4.996%	$ 2,234,160	$ 2,357,985
Taxable New Series			
Bonds, 1998 & 2000, 2005-2021	6.696%	138,310	141,540
	5.109%	2,372,470	2,499,525
Tax-Exempt Variable Rate Series			
Bonds, 2003, 2029-2033		250,000	0
Total revenue bonds outstanding		2,622,470	2,499,525
Less: Current maturities of bonds		121,245	100,015
Total revenue bonds outstanding, net of current maturities		$ 2,501,225	$ 2,399,510

Principal and interest amounts due for each of the next five years and thereafter to maturity are:

(In thousands) Year	Principal	Interest	Total
2005	$ 121,245	$ 127,214	$ 248,459
2006	127,255	121,264	248,519
2007	135,155	114,642	249,797
2008	142,155	107,662	249,817
2009	148,570	100,422	248,992
2010-2014	862,080	377,503	1,239,583
2015-2019	616,925	170,485	787,410
2020-2024	219,085	26,413	245,498
2025-2029	50,000	12,375	62,375
2030-2033	200,000	4,950	204,950
Totals	$2,622,470	$ 1,162,930	$ 3,785,400

The above table includes Senior Lien and Junior Lien Bonds. Interest on the Junior Lien Bonds (Variable Rate Demand Obligations) is assumed to be 0.99% annually for all years. This was the rate in effect for the Variable Rate Demand Obligations as of January 31, 2004. These bonds are scheduled to mature from 2029-2033.

Long-Term Debt Activity

January 31, 2004

(In thousands)	Original Amount	Final Principal Payment	Interest Rates (%)	Balance Outstanding February 1, 2003	Additions During Year	Decreases During Year	Balance Outstanding January 31, 2004
Revenue and Refunding Bonds:							
1992 Tax-exempt	$ 700,805	2017	6.048	$ 68,860	$ 0	$ 0	$ 68,860
1994A Tax-exempt	684,700	2014	5.008	505,150	0	436,185	68,965
1994C Tax-exempt	56,000	2006	5.008	42,710	0	0	42,710
1995 Tax-exempt	125,000	2018	5.500	90,200	0	75,400	14,800
1997 Tax-exempt	350,000	2020	5.738	169,715	0	0	169,715
1997 Tax-exempt	311,170	2014	5.509	115,090	0	12,035	103,055
1998A Tax-exempt	785,515	2021	4.918	650,400	0	31,370	619,030
1998B Taxable	99,615	2020	6.343	93,650	0	1,835	91,815
2000A Tax-exempt	170,770	2017	5.374	23,875	0	4,410	19,465
2000B Taxable	50,425	2021	7.403	47,890	0	1,395	46,495
2001 Tax-exempt	115,280	2011	3.843	115,280	0	8,850	106,430
2002 Tax-exempt	436,090	2017	4.055	436,090	0	0	436,090
2002 Tax-exempt	140,615	2020	4.751	140,615	0	0	140,615
2003 Tax-exempt - Junior Lein	250,000	2033	Variable	0	250,000	0	250,000
2003A Tax-exempt	93,935	2014	3.675	0	93,935	0	93,935
2003 Tax-exempt	350,490	2013	3.081	0	350,490	0	350,490
				2,499,525	694,425	571,480	2,622,470
Less: Bond current maturities				100,015	21,230		121,245
Less: Bond discount (premium)				(62,490)	(48,645)	(7,179)	(103,956)
Less: Bond reacquisition costs				159,744	43,157	44,180	158,721
Revenue Bonds, Net				2,302,256	678,683	534,479	2,446,460
Tax-exempt Commercial Paper				350,000	0	0	350,000
Long-term Debt, Net				$ 2,652,256	$ 678,683	$ 534,479	$ 2,796,460

Long-Term Debt Activity

January 31, 2003

(In thousands)	Original Amount	Final Principal Payment	Interest Rates (%)	Balance Outstanding February 1, 2002	Additions During Year	Decreases During Year	Balance Outstanding January 31, 2003
Revenue and Refunding Bonds:							
1992 Tax-exempt	$ 700,805	2017	6.048	$ 121,615	$ 0	$ 52,755	$ 68,860
1994A Tax-exempt	684,700	2014	5.008	565,570	0	60,420	505,150
1994C Tax-exempt	56,000	2006	5.008	42,710	0	0	42,710
1995 Tax-exempt	125,000	2018	5.500	109,300	0	19,100	90,200
1997 Tax-exempt	350,000	2020	5.738	332,570	0	162,855	169,715
1997 Tax-exempt	311,170	2014	5.509	244,305	0	129,215	115,090
1998A Tax-exempt	785,515	2021	4.918	743,150	0	92,750	650,400
1998B Taxable	99,615	2020	6.343	95,390	0	1,740	93,650
2000A Tax-exempt	170,770	2017	5.374	170,770	0	146,895	23,875
2000B Taxable	50,425	2021	7.403	49,200	0	1,310	47,890
2001 Tax-exempt	115,280	2011	3.843	115,280	0	0	115,280
2002 Tax-exempt	436,090	2017	4.055	0	436,090	0	436,090
2002 Tax-exempt	140,615	2020	4.751	0	140,615	0	140,615
				2,589,860	576,705	667,040	2,499,525
Less: Bond current maturities				77,825	22,190	0	100,015
Less: Bond discount (premium)				(10,542)	(56,803)	(4,855)	(62,490)
Less: Bond reacquisition costs				145,729	54,877	40,862	159,744
Revenue Bonds, Net				2,376,848	556,441	631,033	2,302,256
Tax-exempt Commercial Paper				350,000	0	0	350,000
Long-term Debt, Net				$ 2,726,848	$ 556,441	$ 631,033	$ 2,652,256

Long-Term Liabilities & Deferred Credits

January 31, 2004

(In thousands)	Balance Outstanding February 1, 2003	Additions During Year	Decreases During Year	Balance Outstanding January 31, 2004	Amounts Due within One Year
South Texas Project Nuclear Decommissioning	$ 183,291	$ 27,827	$ 0	$ 211,118	$ 0
Customer Deposits	23,586	10,217	13,868	19,935	0
Long-Term Lease Revenue (Deferred)	656,135	0	22,560	633,575	22,560
	863,012	38,044	36,428	864,628	22,560
Other					
South Texas Project Operation, Pensions and Employee Benefits	10,129	4,260	158	14,231	0
South Texas Project Nuclear Fuel Assessment	1,871	0	596	1,275	0
Project Warm	7,756	627	417	7,966	0
Notes Payable	6,669	0	477	6,192	460
Customer Advances	19,392	20,268	16,503	23,157	0
Insurance Reserves	12,419	5,307	4,654	13,072	0
Deferred Credits	220	24,392	23,280	1,332	0
Other	595	3	0	598	0
Total other liabilities	59,051	54,857	46,085	67,823	460
Total Other Long-Term Liabilities & Deferred Credits	$ 922,063	$ 92,901	$ 82,513	$ 932,451	$ 23,020

Long-Term Liabilities & Deferred Credits

January 31, 2003

(In thousands)	Balance Outstanding February 1, 2002	Additions During Year	Decreases During Year	Balance Outstanding January 31, 2003	Amounts Due within One Year
South Texas Project Nuclear Decommissioning	$ 145,878	$ 37,413	$ 0	$ 183,291	$ 0
Customer Deposits	28,269	38,860	43,543	23,586	0
Long-Term Lease Revenue (Deferred)	678,695	0	22,560	656,135	22,560
	852,842	76,273	66,103	863,012	22,560
Other					
South Texas Project Operation, Pensions and Employee Benefits	8,071	4,372	2,314	10,129	0
South Texas Project Nuclear Fuel Assessment	2,450	0	579	1,871	0
Project Warm	7,371	617	232	7,756	0
Notes Payable	7,608	0	939	6,669	408
Customer Advances	21,115	14,712	16,435	19,392	0
Insurance Reserves	13,632	3,073	4,286	12,419	0
Deferred Credits	2	23,164	22,946	220	0
Other	1,746	238	1,389	595	0
Total other liabilities	61,995	46,176	49,120	59,051	408
Total Other Long-Term Liabilities & Deferred Credits	$ 914,837	$ 122,449	$ 115,223	$ 922,063	$ 22,968

7. Commercial Paper

In 1988, the City Council of San Antonio, Texas (City Council) adopted an ordinance authorizing the issuance of up to $300 million in TECP. This ordinance, as amended in June 1997, provides for funding to assist in the financing of eligible projects, in an aggregate amount not to exceed $450 million. Eligible projects include fuel acquisition, capital improvements to the utility systems, and refinancing or refunding any outstanding obligations which are secured by and payable from a lien on and/or a pledge of net revenues of the Systems. The program s scheduled maximum maturities will not extend beyond November 1, 2028.

The TECP has been classified as long-term in accordance with the refinancing terms under a revolving credit agreement with a consortium of banks, which supports the commercial paper. Under the terms of the agreement, CPS may borrow up to an aggregate amount not to exceed $350 million for the purpose of paying principal due under the TECP. The credit agreement has a term of two years, currently extended until November 1, 2005, and may be renewed for additional periods.

To date, there have been no borrowings under the credit agreement. The TECP is secured by the net revenues of the Systems. Such pledge of net revenues is subordinate and inferior to the pledge securing payment of existing New Series Bonds and Junior Lien Obligations, and any to be issued in the future.

A summary of TECP is as follows:

	January 31, 2004	2003
TECP Outstanding *(In thousands)*	$350,000	$350,000
TECP new money issues *(In thousands)*	$ 0	$ 0
Weighted-average interest rate of outstanding TECP, approximate	1.01%	1.11%
Average life of outstanding TECP (approximate number of days)	86	80

8. Benefit Plans

The City Public Service Pension Plan is a self-administered, single-employer, defined-benefit contributory pension plan (Plan) covering substantially all employees who have completed one year of service. Normal retirement is age 65; however, early retirement is available with 25 years of benefit service and to those employees who are ages 55 or older with at least 10 years of benefit service.

Retirement benefits are based on length of service and compensation, and benefits are reduced for retirement before age 55 with 25 years or more of benefit service, or age 62 with less than 25 years of service. The Plan is sponsored by and may be amended by CPS. Plan net assets, having a market value of $887.0 million at December 31, 2003, and $711.9 million at December 31, 2002, are held in a separate trust that is audited annually and which statements include historical trend information. For further information, contact Compensation and Employee Benefits at CPS.

The current policy of CPS is to establish funding levels, considering annual actuarial evaluations and recommendations of the Administrative/Investment Committee, using both employee and employer contributions. Generally, participating employees contribute 5 percent of their total compensation and are normally fully vested in CPS contribution after completing 7 years of credited service or at age 40.

Employee contributions commence with the effective date of participation, and continue until attaining normal or early retirement age or termination of employment. The balance of Plan contributions is the responsibility of CPS giving consideration to actuarial information, budget controls, legal requirements, compliance and industry and/or community norms.

CPS adopted two Restoration Plans effective January 1, 1998, to supplement benefits paid from the Plan due to federal tax restrictions on benefit amounts. The benefits due under the Restoration Plans have been paid by CPS.

The total employer and employee pension funding, which includes amortization of past service costs using the unit credit cost actuarial method, is summarized as follows:

(In thousands)	1/31/2004	1/31/2003
Employee contributions	$ 9,032	$ 8,733
CPS contributions	7,959	5,213
Total contributions	$ 16,991	$ 13,946
Covered payroll	$186,732	$180,292
Total payroll	$196,609	$194,541

The actuarially determined contribution requirements for 2004 and 2003 were computed using an assumed rate of return of 8.5 percent. For 2004, 2003 and 2002 the past-service costs were amortized over a targeted 10 years. No changes in actuarial cost methods or actuarial assumptions were made in 2004 or 2003, which would affect the comparability of results with the prior year.

CPS contributions to the Plan amounted to 4.3 percent of covered payroll in 2004, 2.9 percent in 2003 and 0.6 percent in 2002.

A schedule of funding progress follows:

	Plan (Calendar) Year Actuarial Valuation Date - (Unaudited)		
(In millions)	01/01/2003	01/01/2002	01/01/2001
1. Actuarial value of assets	$ 783.0	$ 758.2	$ 713.6
2. Actuarial accrued liability (AAL)	$ 748.7	$ 691.8	$ 643.5
3. (Overfunded)/ Unfunded AAL (UAAL): (2) -(1)	$ (34.3)	$ (66.4)	$ (70.1)
4. Funded ratio (1) ÷ (2)	104.6%	109.6%	110.9%
5. Covered payroll	$ 186.7	$ 180.3	$ 165.3
6. UAAL as a percentage of covered payroll: (3) ÷ (5)	(18.4%)	(36.8%)	(42.4%)

Actuarial valuation methods used for the January 1, 2003, 2002, and 2001 include: (a) the five-year smoothed market for asset valuation; (b) the projected unit credit for actuarial accrued liability; and (c) the level dollar open for amortization of pension service costs. The remaining amortization periods for January 1, 2003, 2002, and 2001 are 10.16 years, 18.90 years, and 9.89 years respectively and are calculated using the level dollar open amortization method.

Significant actuarial assumptions used for the January 1, 2003, 2002, and 2001 actuarial valuations include (a) a rate of return on the investment of present and future assets of 8.5 percent per year compounded annually, (b) projected salary increases averaging 5.0 percent, and (c) post-retirement cost-of-living increases of 2.0 percent. The projected salary increases include an inflation rate of 4.0 percent.

CPS annual pension cost and net pension obligation for the fiscal periods ended January 31, 2004, January 31, 2003, and January 31, 2002 were as follows:

(In thousands)	2004	2003	2002
Annual required contribution (ARC)	$ 7,651	$ 4,921	$ 660
Interest on net pension obligation (NPO)	0	0	8
Adjustment to APR	0	0	(14)
Annual Pension Cost (APC)	7,651	4,921	654
CPS contributions in relation to ARC	7,651	4,921	753
Increase (decrease) in NPO	0	0	(99)
Net pension obligation -beginning of year	0	0	99
Net pension obligation -end of year	$ 0	$ 0	$ 0
Percentage of APC contributed	100%	100%	115%

Employees who retired prior to 1983 are receiving annuity payments from an insurance carrier as well as receiving some benefits directly from CPS. CPS costs for 2004 and 2003 were $240 thousand and $281 thousand, respectively, and were recorded when paid.

9. Other Postemployment Benefits

CPS provides certain health care and life insurance benefits for retired employees. Most former CPS employees are eligible for these benefits upon retirement from CPS. Assets of the plans are held as part of CPS Group Health and Life Insurance Plans. Funding of the plans is from both participant and employer contributions determined by annual actuarial and in-house calculations. Retired employees contribute to the health plan in varying amounts depending upon an equity formula that considers age and years of service. The plan may be amended by CPS. The annual cost of retiree health care and life insurance benefits funded by CPS is recognized as an expense of CPS as employer contributions are made to the programs. These retiree costs approximated $4.4 million for 2004 and $3.6 million for 2003. CPS reimbursed certain retirees and their spouses enrolled in Medicare Part B a percentage of the monthly premium. Costs totaled $256 thousand for 2004 and $211 thousand for 2003.

Retired employees and covered dependents contributed $1.9 million for their health care and life insurance benefits in 2004 and $1.3 million in 2003. In 2004, there were approximately 2,261 retirees and covered dependents eligible for health care and life insurance benefits, as compared to approximately 2,201 in 2003.

In view of the potential economic significance of these benefits, CPS has reviewed the present value of the postemployment benefit obligations for current retirees. The January 1 valuations are $74.4 million in 2003 and $65.4 million in 2002 for health and $19.8 million in 2003 and $17.3 million in 2002 for life insurance benefits. The actuarial analysis of the present value of postemployment benefit obligations for other participants fully eligible for benefits are estimated to be $45.9 million for health, $5.6 million for life insurance and $3.0 million for disability benefits. CPS began partial accrual and funding of projected future benefits in 1992. Funding totaled $4.3 million in 2004, $4.8 million in 2003 and $6.5 million in 2002.

For the health plan, the actuarial cost method used is the Projected Unit Credit Actuarial Cost Method. For the life insurance and disability plans, CPS uses a present value method to determine the cost of benefits.

Significant actuarial assumptions used in the calculations for the January 1, 2003 and 2002 actuarial valuations include (a) a rate of return on the investment of present and future assets of 8.5 percent per year for the health, life and the disability plans, (b) projected salary increases for the plans ranging from 4.5 percent to 12.0 percent depending on age for base and other salaries, and (c) medical cost increases projected at 10.0 percent for 2003 decreasing to 6.0 percent in 2011 and thereafter.

10. Risk Management

CPS is exposed to various risks of loss including those related to torts, theft or destruction of assets, errors and omissions, and natural disasters. CPS purchases commercial liability and property insurance coverage to provide protection in event of large and/or catastrophic losses. CPS performs actuarial studies periodically to determine its insurance retentions. An actuarial study was last performed in 2004.

In addition, CPS is exposed to risks of loss due to death of, injuries to, or illnesses of, its employees. At January 31, 2004 and 2003, CPS has accumulated approximately $152.8 million and $122.7 million, respectively, in the employee health and welfare plans external trusts for these risks. The trust accounts and related claims liabilities are included in CPS' financial statements. CPS has recorded $27.7 million of expense related to these risk programs for the year ended January 31, 2004 and $23.8 million for the year ended January 31, 2003.

Based upon the guidance of GASB Statement No. 10, *Accounting and Financial Reporting for Risk Financing and Related Insurance Issues*, the following information is provided regarding the changes in the reserves for property, and employee and public liability claims for the years ended January 31, 2004 and 2003:

(In thousands)	Property Reserves	Employee & Public Liability Claims	Employee Health and Welfare Claims
Balance - 1/31/02	$ 8,624	$ 5,008	$ 3,641
Payments	(52)	(110)	(28,894)
Incurred Claims	0	36	29,425
Other claims adjustments	(3,019)	1,932	0
Balance - 1/31/03	$ 5,553	$ 6,866	$ 4,172
Payments	(95)	(1,000)	(35,415)
Incurred Claims	0	0	35,939
Other claims adjustments	377	1,371	0
Balance - 1/31/04	$ 5,835	$ 7,237	$ 4,696

The employee health and welfare plan assets are segregated from CPS' assets. They are separately managed by a committee whose members are appointed by the CPS General Manager and CEO. These plans have separate financial statements for calendar years 2003 and 2002. These separately audited financial statements are available upon request by contacting Compensation and Employee Benefits at CPS.

The 1999 Texas utility deregulation legislation, Senate Bill 7, contained provisions modifying the Texas Public Funds Investment Act to allow municipal utilities the ability to purchase and sell energy related financial instruments in order to hedge or mitigate the effect of market price fluctuations of natural gas, fuel oil and electric energy.

In 2003, the City Public Service Board of Trustees reaffirmed the Energy Price Risk Management Policy, which sets forth the guidelines for the purchase and sale of certain financial instruments and certain physical products, collectively defined as hedge instruments. Currently, these hedge instrument transactions are used to minimize the risk of market energy price volatility as it relates to the underlying transactions that relate to the physical purchase of natural gas. The primary goals for the Energy Risk Management Policy, which is overseen by the Hedging Strategy Committee, is to mitigate the potential for loss or reduce the uncertainty in expenses, pricing and revenue as a result of unforeseen market changes that pertain to fuel expenses and revenues. The hedge instruments are reported at cost on the Balance Sheets. Gains and losses related to the hedge instruments transactions are netted to fuel expense in the period realized. For January 31, 2004 and January 31, 2003, the commodity options and/or hedge instruments, valued at mark-to-market, net to an unrealized gain of $2,100,006 and $965,398, respectively.

The fair value of option contracts is determined using New York Mercantile Exchange (NYMEX) closing settlement prices as of January 30, 2004. For futures contracts, the fair value is calculated by deriving the difference between the closing futures prices on January 30, 2004 and the futures purchase prices at the time the positions were established, less applicable commissions. As of January 31, 2004, the outstanding hedge instruments total cost is $144,544 with a positive fair value of $2,244,550. In January 31, 2003, total cost for outstanding hedge instruments was $266,348 with a positive fair value of $1,231,747. In the event purchased options are allowed to expire, the related premiums paid to acquire those options will be lost. When a short position is established, and options are sold, premiums are received and an obligation to honor the terms of the option contract, if exercised, is created. The decision whether to exercise the options or let them expire rests with the purchasing party. Futures contracts represent a firm obligation to buy, or sell, the underlying asset. If held to expiration, the contract holder must take delivery of, or deliver, the underlying asset, at the established contract price. Credit risk is mitigated by clearing all hedge-related trades on the NYMEX.

CPS has adopted GASB Technical Bulletin No. 2003-1, *Disclosures Requirements for Derivatives Not Reported at Fair Value on the Statement of Net Assets*. Accordingly, the following information is provided regarding CPS' outstanding Financial Instruments as of January 31, 2004 and January 31, 2003:

Fuel Derivative Transactions as of January 31, 2004

Type of Transaction		Duration	Volumes MMBtu
Short	Call	March 2004 through February 2005	5,310,000
Long	Put	March 2004 through February 2005	5,310,000
Long	NG Futures	March 2004 through February 2005	8,050,000

Fuel Derivative Transactions as of January 31, 2003

Type of Transaction		Duration	Volumes MMBtu
Long	Call	June 2003 through October 2003	2,900,000
Short	Put	September 2003 through October 2003	1,400,000

11. South Texas Project

CPS is one of four participants in the STP, which consists of two 1,250-megawatt nuclear generating units in Matagorda County, Texas. The other participants in the STP are Texas Genco, L.P.- formerly known as Houston Lighting & Power, and Reliant Energy, Inc.; American Electric Power - Central Power and Light Company; and the City of Austin. In-service dates for STP were August 1988 for Unit 1 and June 1989 for Unit 2. CPS' 28 percent ownership in the STP represents 700 megawatts of plant capacity. At January 31, 2004 and 2003, CPS' investment in the STP utility plant was approximately $1.7 billion, net of accumulated depreciation. Effective November 17, 1997, the Participation Agreement among the owners of STP was amended and restated and the STP Nuclear Operating Company (STP OPCO), a Texas non-profit non-member corporation created by the participants, assumed responsibility as the licensed operator of STP. The participants share costs in proportion to ownership interests, including all liabilities and expenses of STP OPCO.

CPS amortizes its share of nuclear fuel for the STP to fuel expense on a unit-of-production method. Under the Nuclear Waste Policy Act of 1982, the federal government assumed responsibility for the permanent disposal of spent nuclear fuel. CPS is charged a fee for disposal of spent nuclear fuel, which is based upon CPS share of the STP generation that is available for sale to CPS customers. This charge is included in fuel expense monthly.

Nuclear Insurance — The Price-Anderson Act is a comprehensive statutory arrangement for providing limitations on liability and governmental indemnities with respect to nuclear accidents or events. The maximum amount that each licensee may be assessed following a nuclear incident at any insured facility is $100.6 million, subject to adjustment for inflation, for the number of operating nuclear units and for each licensed reactor, payable at $10 million per year per reactor for each nuclear incident. CPS and each of the other participants of STP are subject to such assessments, which will be borne on the basis of their respective ownership interests in STP. For purposes of these assessments, STP has two licensed reactors. The participants have purchased the maximum limits of nuclear liability insurance, as required by law, and have executed indemnification agreements with the Nuclear Regulatory Commission (NRC), in accordance with the financial protection requirements of the Price-Anderson Act.

A Master Worker Nuclear Liability policy, with a maximum limit of $600 million for the nuclear industry as a whole, provides protection from nuclear-related claims.

NRC regulations require licensees of nuclear power plants to obtain on-site property damage insurance in a minimum amount of $1.06 billion. NRC regulations also require that the proceeds from this insurance be used first to ensure that the licensed reactor is in a safe and stable condition so as to prevent any significant risk to the public health or safety, and then to complete any decontamination operations that may be ordered by the NRC. Any funds remaining would then be available for covering direct losses to property.

The owners of STP currently maintain $2.75 billion of nuclear property insurance, which is above the legally required amount of $1.06 billion, but is less than the total amount available for such losses. The $2.75 billion of nuclear property insurance consists of $500 million in primary property damage insurance and $2.25 billion of excess property damage insurance, both subject to a retrospective assessment being paid by all members of Nuclear Electric Insurance Limited (NEIL). In the event that property losses as a result of an accident at any nuclear plant insured by NEIL exceed the accumulated fund available to NEIL, a retrospective assessment could occur. The maximum aggregate assessment under current policies for both primary and excess property damage insurance is $25.5 million during any one-policy year.

Nuclear Decommissioning — CPS, together with the other owners of the STP, files with the NRC a certificate of financial assurance for the decommissioning of the nuclear power plant. The certificate assures that CPS will meet the minimum decommissioning funding requirements mandated by the NRC. The STP owners agreed in the financial assurance plan that their estimate of decommissioning costs would be reviewed and updated periodically. In 1995, the owners conducted a review of decommissioning costs. The results estimated CPS share of decommissioning costs at approximately $270 million in 1994 dollars. In 1999, the owners conducted an additional review of decommissioning, and results showed that CPS share of decommissioning costs are now approximately $311 million in 1998 dollars.

In 1991, CPS started accumulating the decommissioning funds in an external trust, in accordance with the NRC regulations. The Decommissioning Trust assets and related liabilities are included in CPS financial statements as a component unit. At January 31, 2004, CPS has accumulated approximately $211.1 million of funds in the external trust. Based on the annual calculation of financial assurance required by the NRC, CPS trust balance exceeded the calculated financial assurance amounts of $70.4 million at December 31, 2003 and $69.1 million at December 31, 2002.

Based upon the 1998 and 1994 decommissioning cost studies, the annual funding level into the trust of $15.9 million for 2004 and 2003, was expensed by CPS.

The Decommissioning Trust also has separate financial statements for calendar year 2003. These separately audited financial statements can be obtained by contacting the Vice President of Financial Services at CPS.

12. Lignite Mining Lease and Assignment Agreement

CPS has an agreement with the Aluminum Company of America (ALCOA) dated December 28, 1998, regarding CPS lignite reserves in Bastrop and Lee Counties, Texas. ALCOA began making advance royalty payments to CPS under the agreement in January 1999. The base term of the agreement runs through 2013. ALCOA has the option to exercise six additional five-year extensions of the agreement. Thus, if ALCOA exercises all six extensions, the agreement will remain in effect until 2043. The agreement provides for royalty payments to CPS based on the amount of lignite mined by ALCOA, subject to certain minimum amounts per year once mining has commenced. The current estimate of the amount of the lignite to be mined by ALCOA under the agreement is 180 million tons over a 30-year period, although ALCOA may mine more or less than this amount. CPS will amortize the basis of the lignite reserves, approximately $18.8 million, as royalty payments are received. CPS received $1.0 million in advance royalty payments in 2003 and 2004. In 2004, CPS received $2.6 million in property possession fees. Alcoa began mine construction in calendar 2003 and now estimates mining will begin by late calendar 2004.

13. Joint Operations Agreement

A 1997 Joint Operations Agreement (JOA) resulted from the litigation settlement with Texas Genco, L.P., formerly known as Houston Lighting & Power Company and Reliant Energy, Inc.. over its management of STP during the construction and early operating periods. The JOA is an arrangement to jointly dispatch CPS and Texas Genco, L.P. s generating plants to take advantage of the most efficient plants and favorable fuel prices of each utility. Until June 2002, CPS received, in monthly cash payments, 90 percent of the savings realized from the jointly-operated systems. As of June 2002, when Texas Genco, L.P. met the JOA $200 million cumulative savings obligation, monthly cash payments to CPS were reduced to 50 percent of the savings realized from the jointly operated systems. As of January 31, 2004, CPS total cumulative payments from savings realized was $235.8 million.

14. Lease/Leaseback

On June 2, 2000, CPS entered into a financial transaction with an affiliate of Unicom involving CPS J.K. Spruce Unit No. 1 coal-fired electric generation unit. The transaction included a headlease for a term of approximately 65 years in combination with a leaseback of the facility by CPS for approximately 33 years. CPS retains fee simple title to and operating control of the facility and retains all revenues generated from sales of electricity produced from the facility. CPS received the appraised fair value of the unit, $725.0 million, which will be amortized over 381 months. The transaction expenses and leaseback costs of $637.0 million were recorded as prepaid items in 2001 and are being amortized over 381 months.

The utility has the option to cancel the headlease after the leaseback expires by making a payment to Unicom s affiliate. CPS entered into a collateralized payment undertaking agreement that will generate funds sufficient to fund the cancellation option payment. CPS net benefits were approximately $88.0 million. The City was paid $12.3 million in accordance with the New Series Bond Ordinance, or its 14 percent share of this net benefit. This payment was recorded as a prepayment in 2001 and is being amortized over 381 months. As a result, net proceeds from the transaction of approximately $75.7 million will be reported over the 32-year leaseback term. In 2004 and 2003, the net amount recorded as income by CPS was $2.8 million and $2.8 million, respectively.

15. Commitments and Contingencies

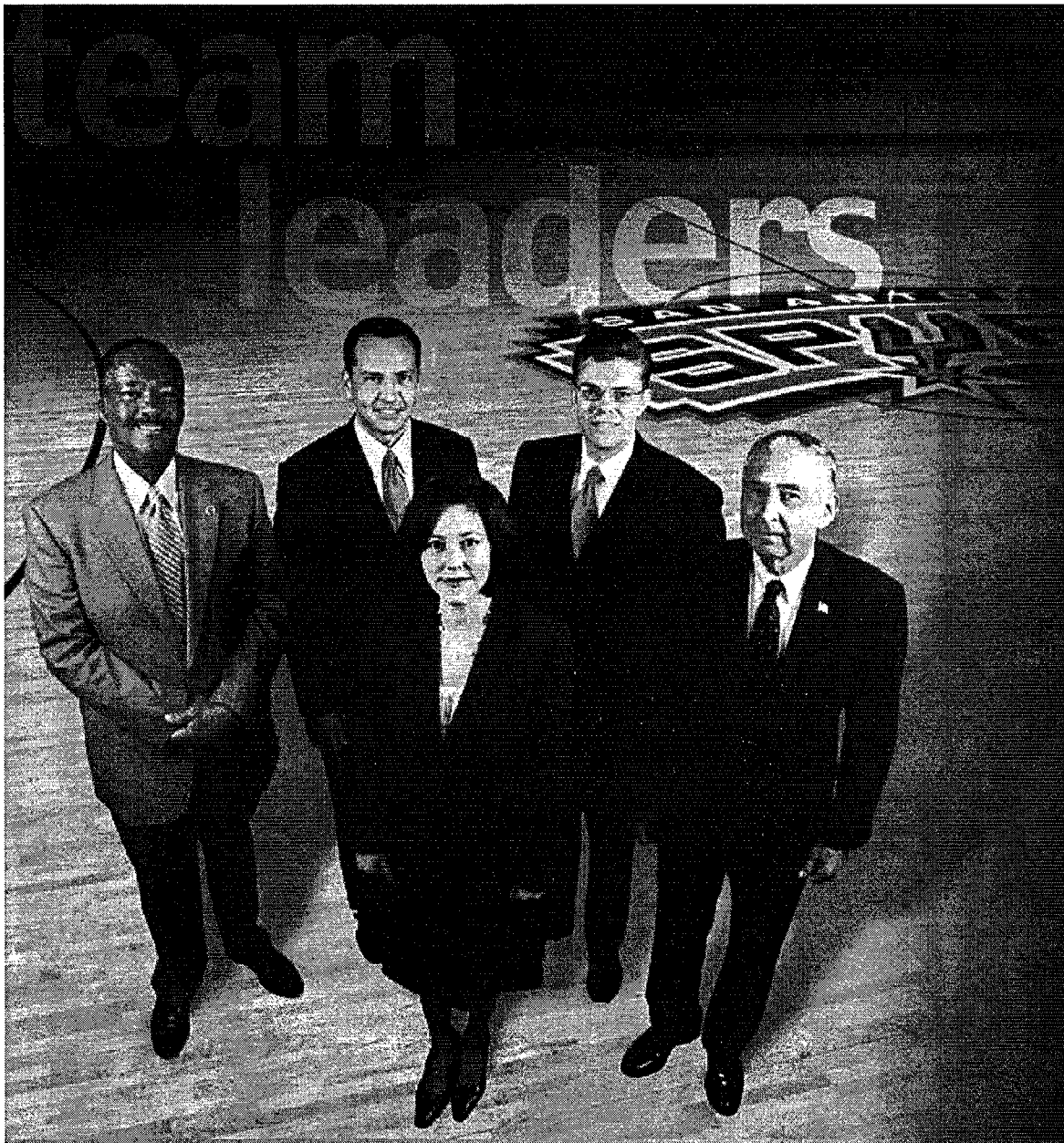
In the normal course of business, CPS is involved in legal proceedings related to alleged personal and property damages, breach of contract, condemnation appeals and discrimination cases. In addition, CPS power generation activities and other utility operations are subject to extensive state and federal environmental regulation. In the opinion of management of CPS, the outcome of such proceedings will not have a material adverse effect on the financial position or results of operations of CPS.

Purchase and construction commitments amounted to approximately $1.5 billion at January 31, 2004. This amount includes approximately $40.3 million that is expected to be paid for natural gas purchases to be made under various contracts currently in effect through June 2007; the actual amount to be paid will depend upon CPS actual requirements during the contract period and the price of gas. Also included is $79.5 million for coal purchases through December 2006, $246.2 million for coal transportation through December 2014, and $3.0 million for treated cooling water through December 2005, based upon the minimum firm commitment under these contracts.

CPS has also committed to purchase $199.5 million in wind power; $22.5 million for generation plant maintenance services; and $50.0 million for system construction and maintenance.

Additional purchase commitments at January 31, 2004, which are related to STP, include approximately $673.3 million for raw uranium, associated fabrication and conversion services. This amount represents services that will be needed for refueling through the year 2028.

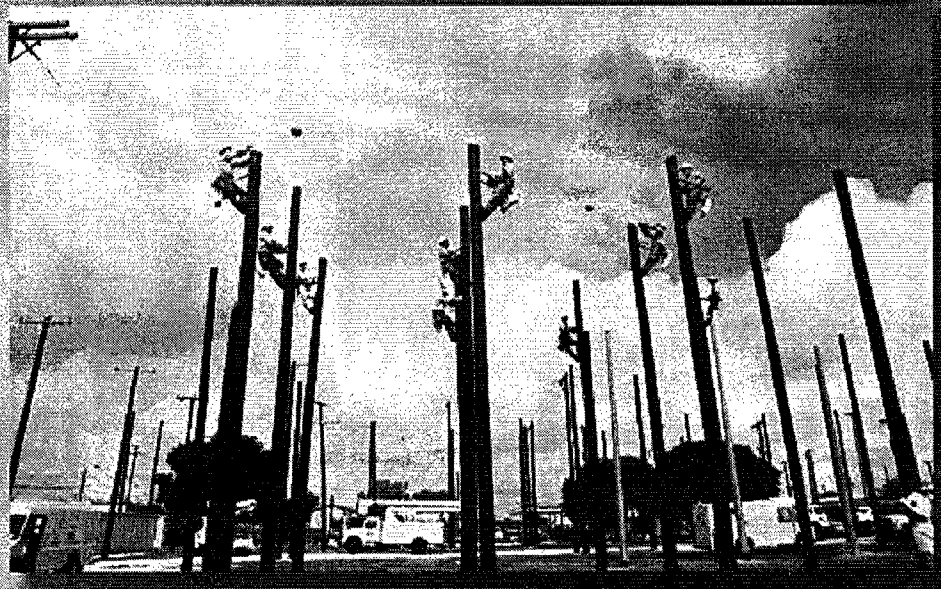
The PUC promulgated new rules in 1996 designed to comply with legislative changes affecting the utility industry. The Transmission Pricing and Access Rule mandates that electric utilities charge customers for wholesale open transmission access according to a formula based on the amount of load served by each utility. CPS cost for calendar years 2002 and 2003 were approximately $11.6 million and $16.1 million, respectively. The estimated cost for calendar year 2004 is approximately $13.0 million.



The City Public Service Board of Trustees, left to right: Clayton T. Gay Jr., Trustee; Ed Garza, Mayor of San Antonio, Ex-Officio Member; Aurora Ortega-Gyll, Vice Chairman; Stephen S. Monaghan, Chairman; Alvaro Sanchez, Jr., Trustee.

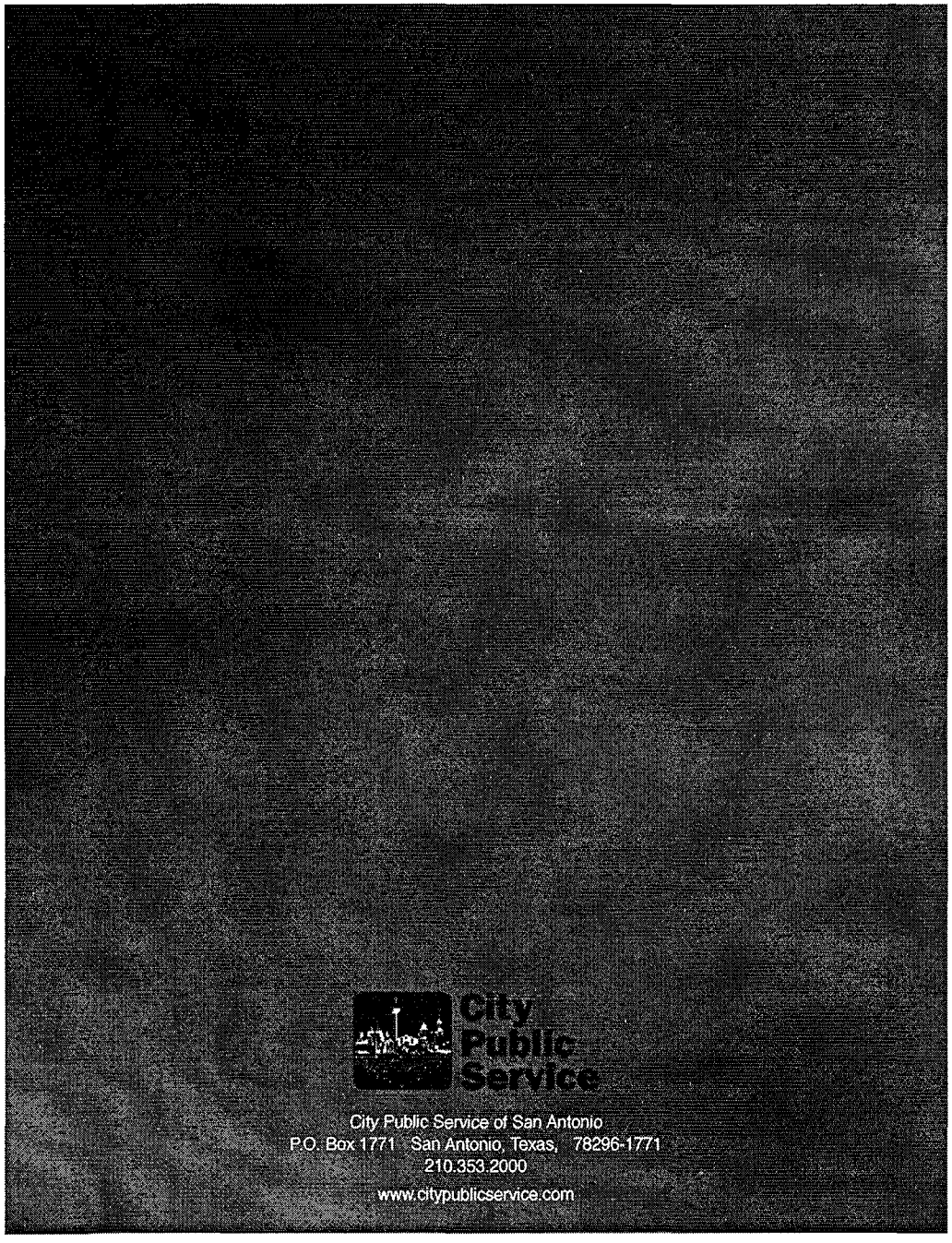
The Citizens Advisory Committee reviews CPS programs and policies, then makes recommendations to CPS staff and the Board of Trustees. Left to right, first row: Thomas Dawsey, Lee Jaye Rosenberg, Theresa Vale, Evangeline O. Sullivan, Terry Dudley, Manuel Garcia III. Left to right, second row: Keith Kolars, Harold E. Tillman, Royal Hammond, Jr., Tony Franckowiak, Reynaldo Nieto, Ralph T. Gomez. Not pictured: Raymond Aguillon, Jr., Gary Candy, Chairman, Jesse Jenkins.

City Public Service Management (left to right) Al Lujan, Senior Vice President, Energy Delivery Systems; Ken Emery, Senior Vice President, Information Management and Shared Services; Milton Lee, General Manager and CEO; Beth Emery, Senior Vice President and General Counsel; V. Gary Scheub, Senior Vice President, Financial and Corporate Services.



PARTING SHOT

Like the San Antonio Spurs, CPS lineman trainees practice their ball handling. Perched atop utility poles, the trainees toss basketballs to each other to develop the balance and agility required to do power line construction and repair work. The training is part of developing a winning team.



City Public Service

City Public Service of San Antonio
P.O. Box 1771 San Antonio, Texas, 78296-1771
210.353.2000
www.citypublicservice.com

TexasGenco

2003 Annual Report

DEAR SHAREHOLDER,

Thank you for your investment in Texas Genco. We are one of the nation's largest independent electric generating companies with a diverse portfolio of power plants. The company owns 60 generating units at 11 facilities in Texas and a 30.8 percent interest in the South Texas Project nuclear generating station. Approximately 4,800 megawatts of our portfolio is coal, lignite and nuclear fuel baseload capacity. The remaining 9,200 megawatts are natural gas fired, with the capability of producing over 3,000 megawatts with fuel oil. We sell capacity, energy and ancillary services in the Texas electric market, which was opened to retail competition in January 2002.

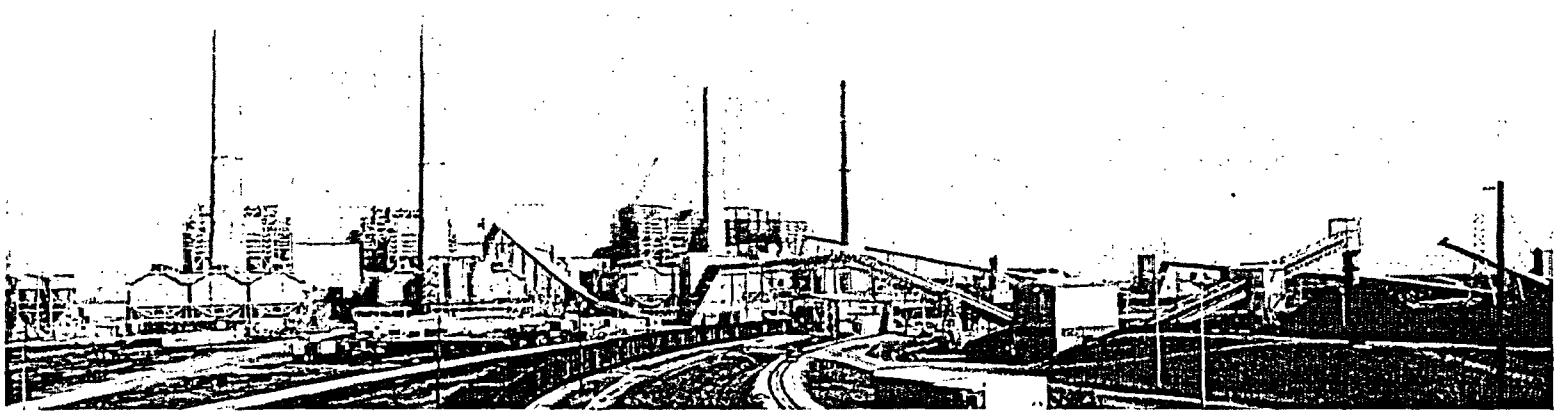
2003 Results Significantly Improved

Overall, 2003 was a good, solid year. We are proud of our performance and believe we have positioned the company well for the future.

Our 2003 financial results were significantly improved over 2002. For 2003, we reported $151 million or $1.89 per share of income before cumulative effect of accounting change compared to a loss of $93 million or $1.16 per share in 2002. This turnaround resulted largely from higher wholesale electricity prices driven by sharp increases in the price of natural gas.

In response to our customers' needs, we developed a number of new products that offered our customers more flexibility to meet the various electricity demands of their own customers. We also continued our practice of seasonal operation at a number of our natural gas fired units and mothballed approximately 2,200 megawatts of capacity at least through April 2005 due to a lack of demand in the marketplace.

We are also pleased with our employees' response to a number of unplanned unit outages during 2003. Unplanned plant outages are a part of operating a large, complex generating fleet. What distinguishes one company from another, however, is the way it responds to these outages. Our employees responded admirably last year to several unplanned outages. We not only repaired these units as quickly and effectively as possible, we also operated the other plants in our fleet to ensure our customers' needs were met at the lowest cost to us.



Environmental Commitment Demonstrated

Texas Genco is an industry leader in reducing emissions and demonstrating new nitrogen oxide (NOx) control technologies. Our power plant fleet currently operates at one of the lowest NOx emission rates in the country. We have spent more than $660 million on new emission controls since 1999. With the installation of additional equipment this year, NOx emissions from Houston area power plants will be reduced by about 88 percent compared to 1998 levels. These actions play a major role in the Houston/Galveston Area Ozone State Implementation Plan and are making a major contribution toward cleaner air in the greater Houston area. The W. A. Parish coal-fired power plant, a 4-unit, 2,462-megawatt facility, is among the lowest NOx emitting coal plants in the nation.

2004 Looks Bright

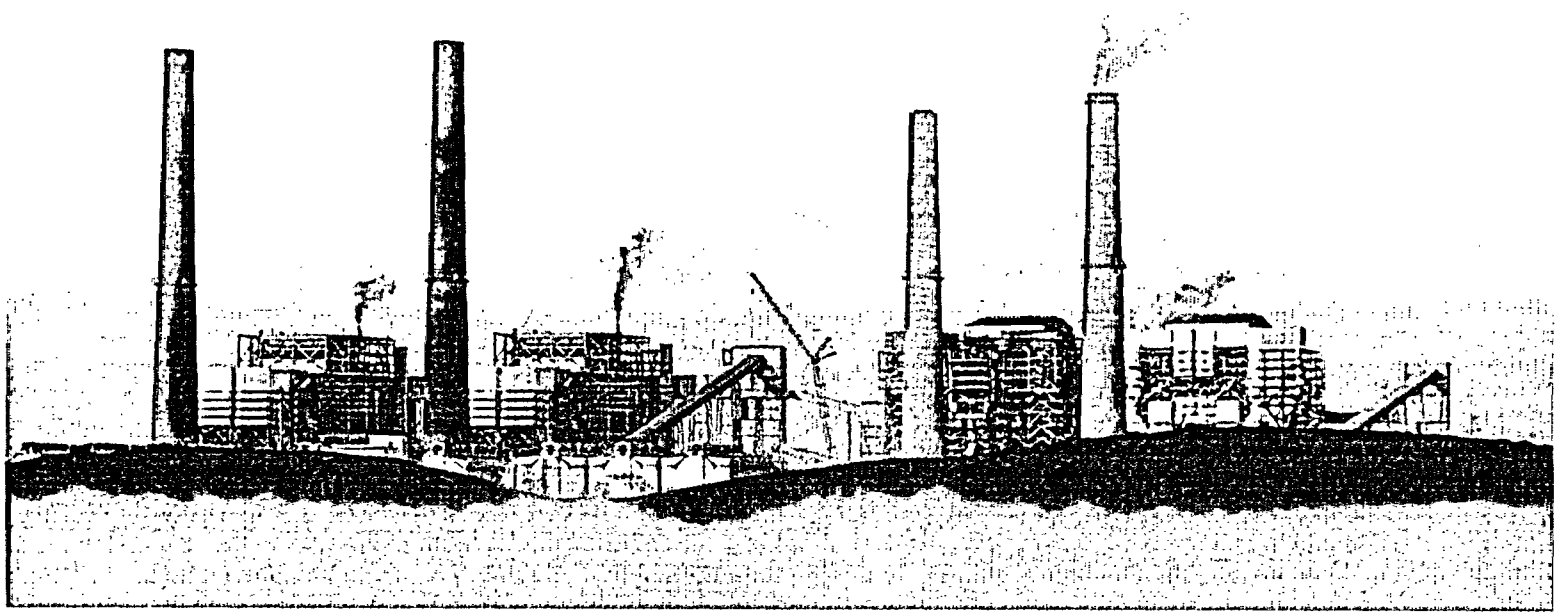
Texas Genco is well positioned for another excellent year and beyond. Wholesale electricity prices remain high and most of the company's 2004 baseload capacity products have been sold at prices significantly above levels experienced in 2003. We have also sold over half of our baseload products for next year, securing a significant portion of our 2005 revenues at attractive prices. We are very focused on maintaining the availability of our baseload generating units and optimizing the economic dispatch of our diverse generating fleet, both of which are essential for our future financial performance. We're looking forward to another good year.

Thank you for your investment in Texas Genco. We are working diligently to earn your continued confidence and increase the value of your investment.

Sincerely,

David M. McClanahan
Chairman

David G. Tees
President and Chief Executive Officer



OFFICERS

David M. McClanahan, 54
Chairman

David G. Tees, 59
President and Chief Executive Officer

Scott E. Rozzell, 54
Executive Vice President
General Counsel and Corporate Secretary

Gary L. Whitlock, 54
Executive Vice President
and Chief Financial Officer

James S. Brian, 56
Senior Vice President
and Chief Accounting Officer

Walter L. Fitzgerald, 46
Vice President
and Controller

Marc Kilbride, 51
Vice President and Treasurer

Joseph B. McGoldrick, 50
Corporate Vice President
Strategic Planning

Michael A. Reed, 50
Vice President
Plant Operations

Rufus S. Scott, 60
Vice President, Deputy
General Counsel and
Assistant Corporate Secretary

Jerome D. Svatek, 48
Vice President
Asset Management

BOARD OF DIRECTORS

J. Evans Attwell, 73, is the retired Managing Partner of Vinson & Elkins L.L.P. Director of Texas Genco since March 2003.

Donald R. Campbell, 63, is a private investor and the retired Chief Financial Officer of Sanders Morris Harris Group, Inc. Director of Texas Genco since March 2003.

Robert J. Cruikshank, 73, is a private investor and retired senior partner with Deloitte & Touche LLP. Director of Texas Genco since March 2003.

Patricia A. Hemingway Hall, 51, is President of Blue Cross and Blue Shield of Texas, Inc., a division of Health Care Service Corporation. Director of Texas Genco since March 2003.

David M. McClanahan, 54, is Chairman of the board of directors. He also serves as director and President and Chief Executive Officer of CenterPoint Energy, Inc. Director of Texas Genco since its inception.

Scott Rozzell, 54, is Executive Vice President, General Counsel and Corporate Secretary of Texas Genco and of CenterPoint Energy, Inc. Director of Texas Genco since March 2003.

David G. Tees, 59, is President and Chief Executive Officer of Texas Genco. Director of Texas Genco since December 2002.

Gary Whitlock, 54, is Executive Vice President and Chief Financial Officer of Texas Genco and of CenterPoint Energy, Inc. Director of Texas Genco since March 2003.

TexasGenco

Texas Genco Holdings, Inc.
1111 Louisiana St.
Houston, Texas 77002
713.207.1111

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

Form 10-K

(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, 2003

or

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

For the transition period from to

Commission File Number 1-31449

Texas Genco Holdings, Inc.

(Exact name of registrant as specified in its charter)

Texas *(State or other jurisdiction of incorporation or organization)*	**76-0695920** *(I.R.S. Employer Identification Number)*
1111 Louisiana **Houston, Texas 77002** *(Address and zip code of principal executive offices)*	**(713) 207-1111** *(Registrant's telephone number, including area code)*

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

Title of each class	Name of each exchange on which registered
Common Stock, par value $.001 per share	New York Stock Exchange

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

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ 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 the 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 ☐

The aggregate market value of the voting stock held by non-affiliates of the Company was $353,182,653 as of June 30, 2003, using the definition of beneficial ownership contained in Rule 13d-3 promulgated pursuant to the Securities Exchange Act of 1934 and excluding shares held by directors and executive officers. As of February 29, 2004, the Company had 80,000,000 shares of Common Stock outstanding.

Portions of the definitive proxy statement relating to the 2004 Annual Meeting of Shareholders of the Company, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2003, are incorporated by reference in Item 10, Item 11, Item 12, Item 13 and Item 14 of Part III of this Form 10-K.

TABLE OF CONTENTS

		Page
	PART I	
Item 1.	Business	1
Item 2.	Properties	26
Item 3.	Legal Proceedings	26
Item 4.	Submission of Matters to a Vote of Security Holders	26
	PART II	
Item 5.	Market for Common Stock and Related Stockholder Matters	26
Item 6.	Selected Financial Data	28
Item 7.	Management's Discussion and Analysis of Financial Condition and Results of Operations	29
Item 7A.	Quantitative and Qualitative Disclosures About Market Risk	40
Item 8.	Financial Statements and Supplementary Data of the Company	42
Item 9.	Changes in and Disagreements with Accountants on Accounting and Financial Disclosure	63
Item 9A.	Controls and Procedures	63
	PART III	
Item 10.	Directors and Executive Officers	63
Item 11.	Executive Compensation	63
Item 12.	Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters	63
Item 13.	Certain Relationships and Related Transactions	63
Item 14.	Principal Accountant Fees and Services	63
	PART IV	
Item 15.	Exhibits, Financial Statement Schedules and Reports on Form 8-K	64

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

From time to time we make statements concerning our expectations, beliefs, plans, objectives, goals, strategies, future events or performance and underlying assumptions and other statements that are not historical facts. These statements are "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. Actual results may differ materially from those expressed or implied by these statements. You can generally identify our forward-looking statements by the words "anticipate," "believe," "continue," "could," "estimate," "expect," "forecast," "goal," "intend," "may," "objective," "plan," "potential," "predict," "projection," "should," "will," or other similar words.

We have based our forward-looking statements on our management's beliefs and assumptions based on information available to our management at the time the statements are made. We caution you that assumptions, beliefs, expectations, intentions and projections about future events may and often do vary materially from actual results. Therefore, we cannot assure you that actual results will not differ materially from those expressed or implied by our forward-looking statements.

Some of the factors that could cause actual results to differ from those expressed or implied by our forward-looking statements are described under "Risk Factors" beginning on page 18 in Item 1 of this report.

You should not place undue reliance on forward-looking statements. Each forward-looking statement speaks only as of the date of the particular statement, and we undertake no obligation to publicly update or revise any forward-looking statements.

PART I

Item 1. ***Business.***

OUR BUSINESS

General

We are a wholesale electric power generating company that owns 60 generating units at 11 electric power generation facilities located in Texas. We also own a 30.8% interest in the South Texas Project Electric Generating Station (South Texas Project), a nuclear generating station with two 1,250 megawatt (MW) nuclear generating units. As of December 31, 2003, the aggregate net generating capacity of our portfolio of assets was 14,153 MW, of which 2,988 MW of gas-fired capacity was mothballed. We sell electric generation capacity, energy and ancillary services within the Electric Reliability Council of Texas, Inc. (ERCOT) market. The ERCOT market consists of the majority of the population centers in the State of Texas and facilitates reliable grid operations for approximately 85% of the demand for power in the state.

In June 1999, the Texas legislature enacted legislation (Texas electric restructuring law) which substantially amended the regulatory structure governing electric utilities in Texas in order to encourage retail electric competition. Under the Texas electric restructuring law, we ceased to be subject to traditional cost-based regulation. Since January 1, 2002, we have been selling generation capacity, energy and ancillary services to wholesale purchasers at prices determined by the market. Accordingly, our historical financial information and operating data, such as demand and fuel data, covering periods prior to 2002 do not reflect what our financial position, results of operations and cash flows would have been had our generation facilities been operated during those periods under the current deregulated ERCOT market.

As a result of requirements under the Texas electric restructuring law and agreements with our parent company, CenterPoint Energy, Inc. (CenterPoint Energy), we were obligated to sell substantially all of our capacity and related ancillary services through 2003 pursuant to capacity auctions. In these auctions, we sell firm entitlements to capacity and ancillary services on a forward basis dispatched within specified operational constraints. In our capacity auctions held through February 2004, we sold entitlements to 85% and 24% of our available capacity for 2004 and 2005, respectively. For more information regarding our auctions, please read "Capacity Auctions and Opportunity Sales" below.

Texas Genco Holdings, Inc. (Texas Genco) is an indirect majority owned subsidiary of CenterPoint Energy. Our portfolio of generation facilities was formerly owned by the unincorporated electric utility division of Reliant Energy, Incorporated (Reliant Energy), the predecessor of CenterPoint Energy Houston Electric, LLC (CenterPoint Houston). CenterPoint Houston is an indirect wholly owned subsidiary of CenterPoint Energy. Reliant Energy conveyed these facilities to us in accordance with a business separation plan adopted in response to the Texas electric restructuring law. For convenience, we describe our business in this report as if we had owned and operated our generation facilities prior to the date they were conveyed to us. On January 6, 2003, CenterPoint Energy distributed approximately 19% of the 80 million outstanding shares of Texas Genco's common stock to CenterPoint Energy's common shareholders. CenterPoint Energy now indirectly owns approximately 81% of the outstanding shares of Texas Genco's common stock. For more information, please read "Background of the Distribution of Texas Genco Shares" below. CenterPoint Energy expects to monetize its 81% interest in Texas Genco in 2004, which could involve the sale of all or a portion of its equity interest in Texas Genco. Pursuant to its plan, CenterPoint Energy has engaged a financial advisor and has solicited indications of interest from a number of potential buyers.

CenterPoint Energy is a registered holding company under the Public Utility Holding Company Act of 1935, as amended (1935 Act). The 1935 Act directs the Securities and Exchange Commission (SEC) to regulate, among other things, transactions among affiliates, sales or acquisitions of assets, issuances of securities, distributions and permitted lines of business. In October 2003, the Federal Energy Regulatory Commission (FERC) granted exempt wholesale generator status to Texas Genco, LP, our wholly owned subsidiary that owns and operates our electric generating plants. As a result, we are exempt from substantially all provisions of the 1935 Act as long as we remain an exempt wholesale generator.

Texas Genco was incorporated in Texas in August 2001. Our executive offices are located at 1111 Louisiana, Houston, Texas 77002, and our telephone number is (713) 207-1111. The generating assets of Texas Genco are owned and operated by Texas Genco, LP, its indirect wholly owned subsidiary. In this report, the terms "we," "us" or similar terms mean Texas Genco and its subsidiaries, unless the context indicates otherwise, while references to Texas Genco mean only the parent company.

We make available free of charge on our Internet website our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after we electronically file such reports with, or furnish them to, the SEC. Additionally, we make available free of charge on our Internet website:

- our Code of Ethics for our Chief Executive Officer and Senior Financial Officers;
- our Ethics and Compliance Code;
- our Corporate Governance Guidelines; and
- the charters of our audit and compensation committees.

Any shareholder who so requests may obtain a printed copy of any of these documents from us. Changes in or waivers of our Code of Ethics for our Chief Executive Officer and Senior Financial Officers and waivers of our Ethics and Compliance Code for directors or executive officers will be posted on our Internet website within five business days and maintained for at least twelve months or reported on Item 10 of our Forms 8-K. Our website address is *www.txgenco.com*.

The ERCOT Market

The ERCOT market consists of the State of Texas, other than a portion of the panhandle, a portion of the eastern part of the state bordering on Louisiana and the area in and around El Paso. The ERCOT market represents approximately 85% of the demand for power in Texas and is one of the nation's largest power markets. The ERCOT market includes an aggregate net generating capacity of approximately 78,000 MW. There are only limited direct current interconnections between the ERCOT market and other power markets in the United States.

The ERCOT market operates under the reliability standards set by the North American Electric Reliability Council. The Public Utility Commission of Texas (Texas Utility Commission) has primary jurisdiction over the ERCOT market to ensure the adequacy and reliability of electricity supply across the state's main interconnected power transmission grid. The ERCOT independent system operator (ERCOT ISO) is responsible for maintaining reliable operations of the bulk electric power supply system in the ERCOT market. Its responsibilities include ensuring that electricity production and delivery are accurately accounted for among the generation resources and wholesale buyers and sellers. Unlike independent systems operators in other regions of the country, the ERCOT market is not a centrally dispatched power pool and the ERCOT ISO does not procure energy on behalf of its members other than to maintain the reliable operations of the transmission system. Members are responsible for contracting sales and purchases of power bilaterally. The ERCOT ISO also serves as agent for procuring ancillary services for those who elect not to provide their own ancillary services.

The amount by which power generating capacity exceeded peak demand (reserve margin) in the ERCOT market has exceeded 30% since 2001, and the Texas Utility Commission and the ERCOT ISO have forecasted the reserve margin for 2004 to continue to exceed 30%. The commencement of commercial operation of new facilities in the ERCOT market will increase the competition within the wholesale power market, which could have a material adverse effect on our business, results of operations, financial condition and cash flows and the market value of our assets. The demand for power in the ERCOT market is seasonal, with higher demand occurring during the warmer months.

Since January 1, 2002, any wholesale producer of electricity that qualifies as a "power generation company" under the Texas electric restructuring law and that can access the ERCOT electric grid is allowed to sell power in the ERCOT market at unregulated rates. Transmission capacity, which may be limited, is needed to effect power sales. In the ERCOT market, buyers and sellers enter into bilateral wholesale capacity, energy and ancillary services contracts or may participate in the centralized ancillary services market, which the ERCOT ISO administers. Also, companies whose power generation facilities were formerly part of integrated utilities, like us, are required to auction entitlements to 15% of their capacity. For additional information regarding these auctions, please read "Capacity Auctions and Opportunity Sales — State-mandated Auctions" below. Wholesale buyers and sellers may also engage in spot market transactions in the ERCOT market.

The transmission capacity available in the ERCOT market affects power sales. The power transfer from generators to meet demand across a transmission line is limited by the transfer capability of the line. Therefore, power sales or purchases from one location to another may be constrained by the power transfer capability between locations. A transmission path with significant power flow, the loss of which may cause system reliability problems, is identified as a commercially significant constraint. When scheduled power transfers across transmission facility elements exceed the transfer capability of such elements, the transmission facility is constrained and transmission congestion is declared by the ERCOT ISO. Transmission congestion is then resolved through the use of ancillary services and unit specific deployments to reduce the transfer across the constrained facility. With the addition of new loads, generators and transmission facilities and the re-rating of older facilities, the commercially significant constraints and transfer capabilities can change. Under current protocol, the commercially significant constraints and the transfer capabilities along these paths are reassessed every year. The single control area of the ERCOT market for 2004 is organized into five congestion zones. The reserve margins may vary by congestion zone. The ERCOT ISO has also instituted direct assignment of congestion cost to those parties causing the congestion. This has the potential to increase the power generator's exposure to the congestion costs associated with transferring power between zones. The Texas Utility Commission has initiated a rulemaking project that proposes to replace the existing zonal wholesale market design with a nodal market design that is based on locational marginal prices for power. One of the stated purposes of the proposed market restructuring is to reduce local (intra-zonal) transmission congestion costs. The market redesign project is expected to take effect in late 2006 at the earliest. We expect that implementation of any new market design will require modifications to our procedures and systems, and will have a potential impact on our staffing. We do not expect our competitive position in the ERCOT market will be adversely affected by the proposed market restructuring.

Capacity Auctions and Opportunity Sales

State-mandated Auctions

As a power generation company that has been unbundled from an integrated electric utility, we are required by the Texas electric restructuring law to sell at auction firm entitlements to 15% of our installed generation capacity on a forward basis for varying terms of up to two years. We refer to the auctions held to satisfy this requirement as "state-mandated auctions." Our obligation to conduct state-mandated auctions will continue until January 1, 2007, unless before that date the Texas Utility Commission determines that loads equal to or exceeding 40% of the electric power consumed in 2000 before the onset of retail competition in Texas by residential and small commercial customers in CenterPoint Houston's service area are being served by retail electric providers not affiliated or formerly affiliated with CenterPoint Energy. Reliant Resources, Inc. (Reliant Resources) is deemed to be an affiliate of CenterPoint Energy for purposes of this test. Reliant Resources is currently not permitted under the Texas electric restructuring law to purchase capacity sold by us in the state-mandated auctions.

The capacity entitlements we are required to offer in the state-mandated auctions are determined by rules adopted by the Texas Utility Commission. Under these rules, we are required to sell entitlements to 15% of our installed generation capacity in blocks of 25 MW each. Texas Utility Commission rules require 50% of the 25 MW blocks we sell in these auctions to consist of one-month allocations, or "strips," 30% to consist of one-

year strips, and 20% to consist of two-year strips. Purchasers of our capacity entitlements offered in the state-mandated auctions may resell them to third parties, other than Reliant Resources. We only auction entitlements to capacity dispatched within specified operational constraints to specific zonal delivery points and the entitlements do not convey any right to have power dispatched from a specific generating unit. This enables us to dispatch our commitments in the most cost-effective manner available. This also exposes us to the potential risk that in the event one of our low-cost base-load facilities is shut down, we may be required to satisfy our commitments with the output of higher cost facilities or with replacement power purchased from third parties in the open market. Additionally, like other power generating companies within ERCOT, we are required to purchase power from certain qualifying facilities under the Public Utility Regulatory Policies Act of 1978 at avoided cost.

The types of capacity entitlements we offer in our state-mandated auctions include:

- base-load entitlements, representing our solid fuel, nuclear powered and certain gas-fired generation capacity, that provide energy at a relatively low fixed price and include limited ancillary service capabilities;
- intermediate entitlements, representing various gas-fired generation capacity, that provide energy indexed to natural gas prices and at a specified heat rate and include flexible ancillary service capabilities;
- cyclic entitlements, representing various other gas-fired generation capacity, that provide energy indexed to natural gas prices and at a specified heat rate and include flexible ancillary service capabilities; and
- peaking entitlements, representing various smaller gas-fired generation capacity, that provide energy indexed to natural gas prices and at a specified heat rate and include limited ancillary service capabilities.

Each of these categories of capacity entitlements is generally designed to have operating characteristics similar to the assumed underlying generating units. For example, base-load entitlements can be started once a month, whereas cyclic entitlements can be started up to 20 times a month.

Contractually-mandated Auctions

Through 2003, we were contractually obligated under an agreement with Reliant Resources to auction entitlements to substantially all of our capacity (less operating reserves) available after our state-mandated auctions. We were permitted to reduce the amount of capacity sold in the contractually-mandated auctions by the amount of operating reserves required to back up our obligations under our capacity auctions. We typically reserve 1,250 MW of our capacity, including 750 MW of base-load capacity, as operating reserves, which can be sold as interruptible power on a system-contingent basis.

Through 2003, Reliant Resources had the contractual right, but not the obligation, to purchase 50% (but not less than 50%) of each type of capacity entitlement we auctioned in the contractually-mandated auctions at the prices established in the auctions. Upon determination of the prices for the capacity entitlements, Reliant Resources was obligated to purchase the capacity it elected to reserve from the auction process at the prices set during the auction for that entitlement. In addition to its reservation of capacity, and whether or not it had reserved capacity in the auction, Reliant Resources was entitled to bid for entitlements in each contractually-mandated auction.

Since Reliant Resources chose not to exercise its option to purchase the shares of Texas Genco's common stock owned by CenterPoint Energy in January 2004, we are no longer obligated to conduct any capacity auctions, other than as required by the Texas Utility Commission's rules. We may continue to sell our capacity in a manner similar to such contractually-mandated auctions as well as seek sales under bilateral contracts for a portion of our capacity in the future. As described below under "— Auction Results," we have made significant forward sales of our 2004 and 2005 capacity pursuant to our auctions.

Auction Pricing Methodology

Revenues derived from our capacity auctions come from two sources: capacity payments and energy payments. Capacity payments are based on the final clearing prices, in dollars per kilowatt-month, determined during the auctions. We bill and collect for these capacity payments on a monthly basis just prior to the month of the entitlement. Energy payments consist of a variety of charges related to the fuel and ancillary services scheduled through our auctioned capacity entitlements. Energy payments for base-load products are tied to fixed prices specified in the auction products while energy payments for gas-based products are recovered through heat rates specified for gas auction products times an index based on the Houston Ship Channel Gas price. Additional charges, referred to as "adders," are included in the energy payments to cover additional costs we incur when we are required to operate our facilities at less efficient operating ranges. We bill for these energy payments on a monthly basis in arrears.

Auction Results

We sold 91% of our available capacity for 2003 through state-mandated auctions and contractually-mandated auctions. In our capacity auctions held through February 2004, we have sold 85% and 24% of our available capacity for 2004 and 2005, respectively. As a result, we have contracted for approximately $1 billion of total revenue with respect to our 2004 capacity and approximately $533 million of total revenue with respect to our 2005 capacity. Our available capacity equals our total net generating capacity less capacity withheld as operating reserves and capacity that is subject to planned outages. Of the 2,988 MW of capacity that we have "mothballed", 2,062 MW were included in our available capacity only for the months of May through September 2003. Reliant Resources purchased 78% of our sold 2003 capacity and, through February 2004, had purchased 79% and 68% of our sold 2004 and 2005 capacity, respectively. We will hold additional auctions to sell our remaining available capacity for 2004 as well as capacity for subsequent years.

In 2003, the market-based prices established in our capacity auctions continued to strengthen. Higher gas prices throughout 2003 positively influenced the prices established in our recent capacity auctions. Generally, higher gas prices increase the capacity prices for our base-load entitlements since natural gas is the marginal fuel for facilities serving the ERCOT market during most hours.

Opportunity Sales

In addition to our capacity auctions, from time to time we sell energy on a short-term basis from the generating capacity we use as operating reserves. Any significant unforeseen outage at our base-load or other facilities could adversely impact revenues generated by these sales. We seek to maximize our opportunity sales by seeking to optimize the dispatching of the various facilities in our generating portfolio. For example, we can meet the gas-fired auction products (intermediate, cyclic and peaking) with generation from our lower cost base-load operating reserves when they are available, since entitlements to our auction products convey no right to specific units. Thus, the availability of our base-load capacity has a significant impact on the level of these opportunity sales through the course of the year.

Our Generation Portfolio

Overview

We own 60 generating units at 11 electric power generation facilities located in Texas. We also own a 30.8% interest in the South Texas Project, a nuclear generating plant consisting of two 1,250 MW generating units. As of December 31, 2003, the aggregate net generating capacity of our combined portfolio of generation assets was 14,153 MW, which represents over 18% of the total net generating capacity serving the ERCOT market.

Summary of Our Generation Facilities (As of December 31, 2003)

Generation Facilities	Net Generating Capacity (in MW) (1)	Number of Units	Dispatch Type	Fuel
W. A. Parish	3,653	9	Base-load, Intermediate, Cyclic, Peaking	Coal/Gas
Limestone	1,602	2	Base-load	Lignite
South Texas Project	770(2)	2	Base-load	Nuclear
Cedar Bayou	2,258	3	Intermediate	Gas/Oil
P. H. Robinson	2,211(3)	4	Intermediate	Gas
San Jacinto	162	2	Intermediate	Gas
T. H. Wharton	1,254(4)	18	Intermediate, Cyclic, Peaking	Gas/Oil
S. R. Bertron	844	6	Cyclic, Peaking	Gas/Oil
Greens Bayou	760	7	Cyclic, Peaking	Gas/Oil
Webster	387(4)	2	Cyclic, Peaking	Gas
Deepwater	174(4)	1	Cyclic	Gas
H. O. Clarke	78	6	Peaking	Gas
Total	14,153	62		

(1) Net generating capacity equals gross maximum summer generating capability less the electric energy consumed at the facility.

(2) Represents our 30.8% interest in the South Texas Project.

(3) All four units at P.H. Robinson are expected to be mothballed through April 2005.

(4) Webster Unit 3 (374 MW), T.H. Wharton Unit 2 (229 MW) and Deepwater Unit 7 (174 MW) are expected to be mothballed through at least April 2004.

Mothballed Facilities

As of December 31, 2003, approximately 2,988 MW of our gas-fired generation capacity was mothballed. We expect that 777 MW of this amount will remain mothballed through April 2004 and the other 2,211 MW will remain mothballed through April 2005. The decision to mothball these units was based on the lack of demand for these types of units in our July and September 2003 capacity auctions combined with high forecasted reserve margins in the ERCOT market.

Base-load and Intermediate Facilities

W.A. Parish. Our W.A. Parish facility is the largest coal and gas-fired power facility in the United States based on total MW of net generating capacity. The facility consists of a coal-fired plant and a gas-fired plant each located near Thompsons, Texas. The coal-fired plant includes four steam generating units for base-load service with an aggregate net generating capacity of 2,462 MW. Two of these units are 646 MW steam units that were placed in commercial service in December 1977 and December 1978, respectively. The other two units are 560 MW and 610 MW steam units that were placed in commercial service in June 1980 and December 1982, respectively.

The gas-fired plant includes five generating units with an aggregate net generating capacity of 1,191 MW. Two of these units are 174 MW steam units that were placed in commercial service in June 1958 and December 1958, respectively. These units were converted for daily cyclic operation and the life of the units was extended in 1990 and 1991. The third unit at this plant is a 278 MW steam unit that was placed in commercial service in March 1961. These three units provide cyclic capacity. The fourth unit is a 552 MW steam unit for intermediate service that was placed in service in June 1968. This plant also has a 13 MW gas

turbine generator unit available for peaking and emergency start-up purposes that was placed in service in July 1967.

Limestone. Our Limestone facility is a lignite-fired base-load facility located approximately 120 miles northwest of Houston. This plant includes two steam generating units with an aggregate net generating capacity of 1,602 MW. The first unit is an 836 MW steam unit that was placed in commercial service in December 1985. The second unit is a 766 MW steam unit that was placed in commercial operation in December 1986.

Cedar Bayou. Our Cedar Bayou facility is a gas and oil-fired intermediate facility located east of Baytown, Texas. This plant includes three generating units with an aggregate net generating capacity of 2,258 MW. The units are 750 MW, 748 MW and 760 MW steam units that were placed in service in December 1970, March 1972 and December 1974, respectively.

P.H. Robinson. Our P.H. Robinson facility is a gas-fired intermediate facility located east of San Leon, Texas. This plant consists of four steam generating units with an aggregate net generating capacity of 2,211 MW. Two of the units are 461 MW units that were placed in service in June 1966 and April 1967, respectively. The third unit is a 552 MW unit that was placed in service in December 1968. The fourth unit is a 737 MW unit that was placed in service in December 1973. This plant is in mothball status through April 2005.

San Jacinto. Our San Jacinto facility is a 162 MW gas-fired intermediate facility located in LaPorte, Texas that produces both steam and power. This plant includes two cogeneration units and associated equipment. Both units began commercial operation in April 1995. Each unit consists of a gas turbine that drives an air-cooled generator with the exhaust from the gas turbine being sent to a heat recovery steam generator.

Cyclic and Peaking Facilities

T.H. Wharton. Our T. H. Wharton facility is a gas and oil-fired intermediate, cyclic and peaking facility located in Houston. This plant consists of 18 steam and gas turbine units with an aggregate net generating capacity of 1,254 MW. This facility includes a 229 MW steam unit for cyclic service that was placed in commercial operation in June 1960 and a 13 MW small gas turbine unit for peaking service that was placed in commercial operation in July 1967. In addition, six 57 MW gas turbines were placed in service at this facility in July 1972. An additional two 57 MW gas turbines and two 104 MW steam turbines were installed in August 1974 and were combined with the six gas turbines already in service to develop two combined cycle units for intermediate service. An additional six 58 MW gas turbines for peaking service were placed in service in November 1975. The 229 MW steam unit is in mothball status through April 2004.

S.R. Bertron. Our S.R. Bertron facility is a gas and oil-fired cyclic and peaking facility located in Deer Park, Texas. This plant consists of four steam electric generating units, one auxiliary boiler for cyclic operations, and two gas turbine generators with an aggregate net generating capacity of 844 MW. The first two units at this plant are 174 MW steam units for cyclic service that commenced commercial operation in April 1956 and March 1958, respectively. Both of these units underwent cyclic conversion and life extension in 1989 and 1990. The third and fourth units at this plant are 230 MW steam units that commenced commercial operation in April 1959 and March 1960, respectively. Both of these units are capable of swinging from an overnight minimum of 40 MW to their rated maximum capacity during peak load hours. This facility also has a 23 MW gas turbine generator and a 13 MW gas turbine generator. Both of these units provide peaking service and commenced commercial operation in July 1967.

Greens Bayou. Our Greens Bayou facility is a gas and oil-fired cyclic and peaking facility located northeast of Houston. This plant consists of one 406 MW steam turbine unit, three 54 MW gas turbine units and three 64 MW gas turbine units and has an aggregate net generating capacity of 760 MW. The 406 MW steam turbine unit provides cyclic service and was placed in commercial service in June 1973. The six gas turbine units provide peaking service and were placed in commercial service in December 1976.

Webster. Our Webster facility is a gas-fired cyclic and peaking facility located southeast of Houston between the towns of Webster and League City. This plant has two units with an aggregate net generating capacity of 387 MW. One of these units is a 374 MW steam unit for cyclic service that was placed in service in May 1965 and the other is a 13 MW gas turbine for peaking service that was placed in commercial operation in July 1967. The 374 MW steam unit is in mothball status through April 2004.

Deepwater. Our Deepwater facility is a gas-fired cyclic facility located in southeastern Harris County, Texas. This facility consists of a 174 MW steam unit that commenced commercial operation in 1955 and underwent a life extension and conversion for cyclic operation in 1992. This unit is in mothball status through April 2004.

H.O. Clarke. Our H.O. Clarke facility is a gas-fired peaking facility located in Houston that began operation in 1943. This plant currently consists of six simple-cycle air-cooled gas turbine generating units with an aggregate net generating capacity of 78 MW that were placed in service in June 1968.

South Texas Project

General. The South Texas Project is one of the largest nuclear powered generating facilities in the United States based on total MW of net generating capacity. This facility is located near Bay City, Texas and consists of two 1,250 MW generating units, the first of which commenced operation in August 1988 and the second in June 1989. We own a 30.8% interest in the South Texas Project and bear a corresponding 30.8% share of the capital and operating costs associated with the project. The South Texas Project is owned as a tenancy in common among us and three other co-owners. Each co-owner retains its undivided ownership interest in the two nuclear-fueled generating units and the electrical output from those units. We and the other three co-owners organized STP Nuclear Operating Company (STPNOC) to operate and maintain the South Texas Project. STPNOC is managed by a board of directors composed of one director appointed by each of the co-owners, along with the chief executive officer of STPNOC.

The two South Texas Project generating units operate under licenses granted by the Nuclear Regulatory Commission (NRC) that expire in 2027 and 2028. These licenses could potentially be extended for additional twenty-year terms if the project satisfies NRC requirements.

Right of First Refusal. In early March 2004, one of the other co-owners of the South Texas Project announced it had entered into an agreement to sell its 25.2% ownership interest for approximately $332.6 million, subject to certain closing adjustments. As a result, under the terms of the ownership arrangements for the South Texas Project, we have the right of first refusal to purchase our proportionate share of the interest being sold on the same terms as the third party purchaser, but we must give notice of our election within ninety days.

Decommissioning Trusts. CenterPoint Houston has been authorized to collect $2.9 million per year from customers using its transmission and distribution services and is obligated to deposit the amount collected into external trusts created to fund our 30.8% share of the decommissioning costs for the South Texas Project. As of December 31, 2003, the fair market value of the investments in the external trusts established to fund our 30.8% interest was $189 million.

In July 1999, an outside consultant estimated our 30.8% share of the decommissioning costs to be approximately $363 million in 1998 dollars. The consultant's calculation of decommissioning costs for financial planning purposes used the "DECON" methodology, one of the three alternatives acceptable to the NRC, and assumed deactivation of the project's two generating units upon the expiration of their 40-year operating licenses. The DECON methodology involves removal of all radioactive material from the site following permanent shutdown. The facility operator may then have unrestricted use of the site with no further requirement for a license. The consultant's calculation also assumed that the remainder of the plant systems and structures on site, not previously removed in support of license termination, are dismantled and the site restored.

The owners of the South Texas Project must provide a report on the status of decommissioning funding to the NRC every two years. The report compares external trust funding levels to minimum decommissioning

amounts calculated in accordance with NRC requirements. We first determine our decommissioning cost estimate by escalating the NRC's estimated decommissioning cost of $105 million per unit, expressed in 1986 dollars, for the effects of inflation between 1986 and the recent year-end and then multiplying by 30.8% to reflect our share of each unit of the South Texas Project. We then use this estimate to determine the minimum required level of funding as of the most recent year-end. The calculation of the NRC minimum funding level reflects that funding of the external trusts occurs over the operating lives of the generating units. Therefore, the minimum funding level is generally less than the estimated decommissioning cost. The last report was submitted to the NRC in March 2003 and showed that, as of December 31, 2002, the aggregate NRC minimum funding level was $70.2 million. While the trusts' funding levels have historically exceeded minimum NRC funding requirements, we cannot assure you that the amounts held in trust will be adequate to cover the actual decommissioning costs of the South Texas Project. These costs may vary because of changes in the assumed date of decommissioning and changes in regulatory requirements, technology and costs of labor, materials and equipment.

The investment of the funds in the external trusts is managed in accordance with applicable laws and regulations and by a committee composed of our representatives and representatives of CenterPoint Energy. Pursuant to the terms of an agreement between Reliant Energy and Reliant Resources and the applicable NRC regulations, the responsibility for the decommissioning trusts transferred to us at the time of Reliant Energy's corporate restructuring. In the event that funds from the trusts are inadequate to decommission the facilities, CenterPoint Houston will be required to collect through rates or other authorized charges all additional amounts required to fund our obligations relating to the decommissioning of the South Texas Project. Following the completion of the decommissioning, if surplus funds remain in the decommissioning trusts, the excess will be refunded to the rate payers of CenterPoint Houston or its successor.

Technical Services and Support Facilities

We have a central support facility that we use to support our generation facilities that we refer to as our "EDC facility." This facility includes office space, a maintenance shop, a chemical lab, a warehouse facility and a fleet maintenance garage. Reliant Resources leases a portion of this facility from us.

Under a technical services agreement, Reliant Resources is obligated to provide engineering and technical support services and certain environmental, safety and industrial health services to support the operation and maintenance of our facilities. We have notified Reliant Resources that its obligation to provide these support services will be terminated effective May 31, 2004. Under the agreement, Reliant Resources is also obligated to provide systems, technical, programming and consulting support services and hardware maintenance, excluding plant-specific hardware, necessary to provide generation system planning, dispatch, and settlement and communication with the ERCOT ISO. A project is currently underway to identify manpower requirements, evaluate systems alternatives, define costs and develop time lines for replacement of those services considered necessary under the current overall technical services agreement with Reliant Resources. We paid Reliant Resources approximately $28.4 million for providing these services during 2003. The technical services agreement will terminate upon the sale of CenterPoint Energy's interest in Texas Genco.

Fuel Supplies

We rely primarily on natural gas, coal, lignite and uranium to fuel our generation facilities. The fuel mix of our generating portfolio, based on actual fuel usage during 2003, was approximately 52% coal and lignite, 21% natural gas, and 27% nuclear for the year 2003. As of December 31, 2003, the fuel mix of our generating portfolio based on the capacity of our facilities including mothballed capacity was approximately 66% natural gas, 29% coal and lignite and 5% nuclear. Based on our current assumptions regarding the cost and availability of fuel, plant operation schedules, load growth, load management and the impact of environmental regulations, we do not expect the mix of fuel used by our generating portfolio will vary materially during 2004 from 2003. We substantially collect the underlying cost of fuel through energy payments. As a result of new air emissions

standards imposed by federal and state law, we anticipate having additional costs for certain environmental equipment in 2004 and subsequent years.

Natural Gas

We have long-term natural gas supply contracts with several suppliers. Substantially all of our long-term contracts contain pricing provisions based on fluctuating spot market prices. In 2003, we purchased approximately 50% of our natural gas requirements under these long-term contracts. We purchased the remaining 50% of our natural gas requirements in 2003 on the spot market. Based on current market conditions, we believe we will be able to replace the supplies of natural gas covered under our long-term contracts when they expire with gas purchased on the spot market or under new long-term or short-term contracts. Our natural gas consumption and cost information for 2003 was as follows:

2003 average daily consumption	311 Bbtu(1)
2003 peak daily consumption	942 Bbtu
2003 average cost of natural gas	$5.59 per MMBtu(2)

(1) Billion British thermal units, or "Bbtu."

(2) Compared to $3.32 per million British thermal units, or "MMBtu," in 2002 and $4.28 per MMBtu in 2001.

We lease gas storage facilities capable of storing 6.3 billion cubic feet of natural gas, of which 4.2 billion cubic feet is working capacity. We use these storage facilities to assist us in:

- managing the volatility of the gas requirements of our generating facilities;
- meeting the gas requirements of our generating facilities during periods of inadequate gas supplies; and
- managing our gas-related costs.

Our natural gas requirements are generally more volatile than our other fuel requirements because we use natural gas to fuel our intermediate, cyclic and peaking facilities and other more economical fuels to fuel our base-load facilities. Since our intermediate and peaking facilities are dispatched to meet the variations of demand for electricity, our gas requirements are highly variable, on both an hour-to-hour and day-to-day basis. Although natural gas supplies have been sufficient in recent years to supply our generating portfolio, available supplies are subject to potential disruption due to weather conditions, transportation constraints and other events. As a result of these factors, supplies of natural gas may become unavailable from time to time or prices may increase rapidly in response to temporary supply constraints or other factors.

Coal and Lignite

In 2003, we purchased approximately 80% of the fuel requirements for our four coal-fired generating units at our W.A. Parish facility under two fixed-quantity long-term supply contracts scheduled to expire in 2010 and 2011. The price for coal under the first contract was tied to spot market prices in 2003. The price for coal under the second contract was at a level approximately three times greater than the spot market prices for coal as of December 31, 2003. The second contract does not contemplate future prices being tied to spot market prices. The terms of this contract result from the market conditions in effect during the 1970's when the contract was entered into, including shortages of natural gas supplies, increased demand for low sulfur coal as a result of new environmental regulations and uncertainty regarding the future availability of long-term sources of coal supply. We purchase our remaining coal requirements for our W.A. Parish facility under short-term contracts. We have long-term rail transportation contracts with Burlington Northern Santa Fe Railroad and the Union Pacific Railroad Company to transport coal to our W.A. Parish facility. Despite the higher coal prices under these long-term contracts, our fuel costs associated with producing energy from our coal-fired facilities are, based on recent natural gas prices, significantly lower than the fuel costs associated with producing energy from our gas-fired facilities.

We obtain the lignite used to fuel the two generating units of our Limestone facility from a surface mine adjacent to the facility. We own the mining equipment and facilities and a portion of the lignite reserves located at the mine. Mining operations are conducted by the owner of the remaining lignite reserves. In the past, we have obtained our lignite requirements under a long-term contract on a cost-plus basis. Since July 2002, we have obtained our lignite requirements under an amended long-term contract with the owner/operator at a fixed price determined annually that is expected to result in a cost of generation at the Limestone facility equivalent to the cost of generating with low sulfur Western coal. We expect the lignite reserves will be sufficient to provide all of the lignite requirements of this facility through 2015.

We used a blend of lignite and Wyoming coal to fuel our Limestone facility in 2003 as a component of our oxides of nitrogen (NOx) control strategy. A fuel unloading and handling system was installed at the Limestone facility to accommodate the delivery of Wyoming coal. We expect that we will obtain Wyoming coal through spot and long-term market priced contracts. Our Limestone facility is connected with the Burlington Northern Santa Fe Railroad.

Nuclear

The South Texas Project satisfies its fuel supply requirements by acquiring uranium concentrates, converting uranium concentrates into uranium hexafluoride, enriching uranium hexafluoride, and fabricating nuclear fuel assemblies. We are party to a number of contracts covering a portion of the fuel requirements of the South Texas Project for uranium, conversion services, enrichment services and fuel fabrication. Other than a fuel fabrication agreement that extends for the life of the South Texas Project, these contracts have varying expiration dates, and most are short to medium term (less than seven years). We believe that sufficient capacity for nuclear fuel supplies and processing exists to permit normal operations of the South Texas Project's nuclear powered generating units.

Fuel Pipeline

We own a 90-mile fuel pipeline that can transport either fuel oil or natural gas (86 miles oil or gas and 4 miles gas only). As part of our system, we own over six million barrels of oil storage capacity that can supply fuel oil to our Cedar Bayou, Greens Bayou, S.R. Bertron and T.H. Wharton plants. For natural gas supply, our pipeline is connected to six of our generation facilities and is interconnected with several of our suppliers. Our pipeline provides us with added flexibility in managing the fuel supply requirements of our generation facilities.

Joint Operating Agreement with City of San Antonio

We have a joint operating agreement with the City Public Service Board of San Antonio (CPS) to jointly dispatch our portfolio of generating units with CPS' portfolio of 4,823 MW of generating capacity as a joint operating system to meet our combined obligations. The combined system includes approximately 19,000 MW of generating capacity and provides us with added economies of scale and production cost savings. A large portion of the benefit of joint operations is due to San Antonio's significant amount of capacity at its coal-fired generation facilities. We share the fuel cost savings realized under the agreement with the City of San Antonio. We currently share the cost savings benefits equally with CPS. The current agreement with CPS expires in 2009. Both parties are permitted to sell their capacity outside of the joint operating system if it is economically prudent to do so, in which case the parties would lose the agreement's cost savings benefits with respect to those sales. The capacity of CPS' generating facilities covered by the joint operating agreement is not included in the capacity auctions described under "Capacity Auctions and Opportunity Sales" above.

Competition

The ERCOT market is highly competitive. We have approximately 80 competitors that include generation companies affiliated with Texas-based utilities, independent power producers, municipal or co-operative generators and wholesale power marketers. These competitors compete with each other and us by

buying and selling wholesale power in the ERCOT market, entering into bilateral contracts and/or selling to aggregated retail customers.

As of December 31, 2003, our facilities provided over 18% of the aggregate net generating capacity serving the ERCOT market. Our competition is based primarily on price but we also may compete based on product flexibility. A number of our competitors are building efficient, combined cycle power plants that are generally not able to provide the operational flexibility, ancillary services and fuel risk mitigation that our large diversified portfolio of generating facilities can provide. In addition, we believe that there may be significant excess generating capacity constructed in the ERCOT market over the next several years. This overbuilding could result in lower prices for wholesale power in the ERCOT market. For more information regarding this trend and other competitive factors in the ERCOT market, please read "The ERCOT Market" above and "Risk Factors — Market Risks" below.

Customers

Since January 1, 2002, we have sold power to wholesale purchasers, including retail electric providers, at unregulated rates through our capacity auctions. In addition to retail electric providers, our customers in the ERCOT market include municipal utilities, electric co-operatives, power trading organizations and other power generating companies. We are also a significant provider to the ancillary services market operated by the ERCOT ISO. Sales to subsidiaries of Reliant Resources represented approximately 71% of our total revenues in 2003. We have been granted a security interest in accounts receivable and/or securitization notes associated with the accounts receivable of certain subsidiaries of Reliant Resources to secure up to $250 million in purchase obligations.

Insurance

General

We carry insurance coverage consistent with companies engaged in similar commercial operations with similar properties. Our insurance coverage includes:

- general liability insurance, covering liabilities to third parties for bodily injury and property damage resulting from our operations;
- automobile liability insurance, for all owned, non-owned and hired vehicles, covering liabilities to third parties for bodily injury and property damage; and
- property insurance, subject to replacement cost of insured real and personal property, including coverage for boiler and machinery breakdowns, earthquake and flood damage, subject to certain sublimits.

We also maintain substantial excess liability insurance coverage above the established primary limits for general liability and automobile liability insurance. Limits and deductibles are comparable to those carried by other electric generation companies of similar size. However, our insurance policies are subject to certain limits and deductibles and do not include business interruption coverage. Adequate insurance coverage in the future may be more expensive or may not be available in the future on commercially reasonable terms. Also, the insurance proceeds received for any loss of or any damage to any of our generation facilities may not be sufficient to restore the loss or damage without negative impact on our financial condition, results of operations and cash flows.

Nuclear

We and the other owners of the South Texas Project maintain nuclear property and nuclear liability insurance coverage as required by law and periodically review available limits and coverage for additional protection. The owners of the South Texas Project currently maintain $2.75 billion in property damage insurance coverage, which is above the legally required minimum, but is less than the total amount of insurance currently available for such losses.

Under the Price Anderson Act, the maximum liability to the public of owners of nuclear power plants was $10.6 billion as of December 31, 2003. Owners are required under the Price Anderson Act to insure their liability for nuclear incidents and protective evacuations. We and the other owners of the South Texas Project currently maintain the required nuclear liability insurance and participate in the industry retrospective rating plan under which the owners of the South Texas Project are subject to maximum retrospective assessments in the aggregate per incident of up to $100.6 million per reactor. The owners are jointly and severally liable at a rate not to exceed $10 million per incident per year. In addition, the security procedures at this facility have been enhanced to provide additional protection against terrorist attacks.

We cannot assure you that all potential losses or liabilities associated with the South Texas Project will be insurable, or that the amount of insurance will be sufficient to cover them. Any substantial losses not covered by insurance would have a material adverse effect on our financial condition, results of operations and cash flows.

Background of the Distribution of Texas Genco Shares

Under the Texas electric restructuring law, transmission and distribution utilities whose generation assets were "unbundled" pursuant to the law, including CenterPoint Houston, are entitled to recover their "stranded costs" associated with those assets. The Texas electric restructuring law defines stranded costs as the positive excess of the regulatory net book value of the utility's unbundled generation assets over the market value of those assets, after taking specified factors into account. The law allows alternate methods for establishing a market value for generation assets, including outright sale, full or partial stock market valuation and asset exchanges. Under Reliant Energy's business separation plan, Reliant Energy proposed that the fair market value of our generating assets would be determined using the partial stock market valuation method. CenterPoint Energy distributed 19% of Texas Genco's outstanding shares of common stock to its shareholders in order to establish a public market value for our shares that will be used in 2004 to calculate how much CenterPoint Houston will be able to recover as stranded costs and to comply with CenterPoint Energy's contractual obligations to Reliant Resources.

Beginning in January 2004, on a schedule established by the Texas Utility Commission, investor-owned utilities in Texas may file to commence true-up proceedings. CenterPoint Houston will make the filing to initiate its final true-up proceeding on March 31, 2004. One of the purposes of the true-up proceeding for CenterPoint Energy will be to quantify the amount of stranded costs associated with our generation assets. In the proceeding, the regulatory net book value of our generating assets will be compared to the market value based on the partial stock valuation method. The resulting difference, if positive, is stranded cost that will be recoverable by CenterPoint Houston either through a transition charge, which is a non-bypassable charge, or through a securitization of such cost. Texas Genco is not entitled to receive any payment or other benefits in connection with CenterPoint Houston's true-up proceeding. In the true-up proceeding, the market value of our assets will be based on the average daily closing price of Texas Genco's common stock on The New York Stock Exchange for the 30 consecutive trading days chosen by the Texas Utility Commission out of the last 120 days immediately preceding the true-up filing, plus a control premium, up to a maximum of 10%, to the extent included in the valuation determination made by the Texas Utility Commission.

REGULATION

We are subject to regulation by various federal, state and local governmental agencies, including the regulations described below and under "The ERCOT Market," "Capacity Auctions and Opportunity Sales — State-mandated Auctions" and "Environmental Matters — Regulation" below.

Federal Energy Regulatory Commission

In October 2003, the FERC granted exempt wholesale generator status to Texas Genco, LP, our wholly owned subsidiary that owns and operates our electric generating plants. As a result, we are exempt from substantially all provisions of the 1935 Act as long as we remain an exempt wholesale generator.

Nuclear Regulatory Commission

We are subject to regulation by the NRC with respect to the operation of the South Texas Project. This regulation involves testing, evaluation and modification of all aspects of plant operation in light of NRC safety and environmental requirements. Continuous demonstrations to the NRC that plant operations meet applicable requirements are also required. The NRC has the ultimate authority to determine whether any nuclear powered generating unit may operate.

We and the other owners of the South Texas Project are required by NRC regulations to estimate from time to time the amounts required to decommission that nuclear generating facility and are required to maintain funds to satisfy that obligation when the plant ultimately is decommissioned. CenterPoint Houston currently collects through its electric rates amounts calculated to provide sufficient funds at the time of decommissioning to discharge these obligations. Funds collected are deposited into nuclear decommissioning trusts. The beneficial ownership of the decommissioning trusts is held by us, as a licensee of the facility. While current funding levels exceed NRC minimum requirements, no assurance can be given that the amounts held in trust will be adequate to cover the actual decommissioning costs of the South Texas Project. Such costs may vary because of changes in the assumed date of decommissioning and changes in regulatory requirements, technology and costs of labor, materials and waste burial. In the event that funds from the trusts are inadequate to decommission the facilities, CenterPoint Houston will be required to collect through rates or other authorized charges additional amounts required to fund our obligations relating to the decommissioning of the South Texas Project. For additional information regarding the decommissioning trust, please read "Our Generation Portfolio — South Texas Project — Decommissioning Trusts" above.

ENVIRONMENTAL MATTERS

Regulation

We are subject to a number of federal, state and local laws and regulations relating to the protection of the environment and the safety and health of company personnel and the public. These requirements relate to a broad range of our activities, including:

- the discharge of pollutants into the air, water and soil;
- the identification, generation, storage, handling, transportation, disposal, record keeping, labeling and reporting of, and the emergency response in connection with, hazardous and toxic materials and wastes, including asbestos, associated with our operations;
- noise emissions from our facilities; and
- safety and health standards, practices and procedures that apply to the workplace and the operation of our facilities.

In order to comply with these requirements, we may need to spend substantial amounts and devote other resources from time to time to:

- construct or acquire new equipment;
- acquire permits and/or marketable allowance or other emission credits for facility operations;
- modify or replace existing and proposed equipment; and
- clean up or decommission waste disposal areas, fuel storage and management facilities, and other locations and facilities, including generation facilities.

If we do not comply with environmental requirements that apply to our operations, regulatory agencies could seek to impose on us civil, administrative and/or criminal liabilities as well as seek to curtail our operations. Under some statutes, private parties could also seek to impose upon us civil fines or liabilities for property damage, personal injury and possibly other costs.

Under the federal Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA), owners and operators of facilities from which there has been a release or threatened release of hazardous substances, together with those who have transported or arranged for the disposal of those substances, are liable for:

- the costs of responding to that release or threatened release; and
- the restoration of natural resources damaged by any such release.

Air Emissions

As part of the 1990 amendments to the Federal Clean Air Act, requirements and schedules for compliance were developed for attainment of health-based standards. In furtherance of the Act's requirements, standards for NOx emissions, a product of the combustion process associated with power generation, have been finalized by the Texas Commission on Environmental Quality ("TCEQ"). These TCEQ standards, as well as provisions of the Texas electric restructuring law, require substantial reductions in NOx emissions from electric generating units. We are currently installing cost-effective controls at our generating plants to comply with these requirements. As of December 31, 2003, we have invested $664 million for NOx emissions controls and are planning to make additional expenditures of $131 million through 2007. Further revisions to these NOx standards may result from the TCEQ's future rules, expected by 2007, implementing more stringent federal eight-hour ozone standards.

In 1998, the United States became a signatory to the United Nations Framework Convention on Climate Change (Kyoto Protocol). The Kyoto Protocol calls for developed nations to reduce their emissions of greenhouse gases. Carbon dioxide, which is a major byproduct of the combustion of fossil fuel, is considered to be a greenhouse gas. In 2002, President Bush withdrew the United States' support for the Kyoto Protocol while endorsing voluntary greenhouse gas reduction measures. Congress has also explored a number of other alternatives for regulating domestic greenhouse gas emissions. If the country re-enters and the United States Senate ultimately ratifies the Kyoto Protocol and/or if the United States Congress adopts other measures for the control of greenhouse gases, any resulting limitations on power plant carbon dioxide emissions could have a material adverse impact on all fossil fuel-fired electric generating facilities, including those belonging to us.

In July 2002, the White House sent to the United States Congress a Bill proposing the Clear Skies Act, which is designed to achieve long-term reductions of multiple pollutants produced from fossil fuel-fired power plants. If enacted, the Clear Skies Act would target reductions averaging 70% for sulfur dioxide (SO_2), NOx and mercury emissions and would create a gradually imposed market-based compliance program that would come into effect initially in 2008 with full compliance required by 2018. Fossil fuel-fired power plants owned by companies such as us would be affected by the adoption of this program, or other legislation currently pending in Congress addressing similar issues. To comply with such programs, we and other regulated entities could pursue a variety of strategies, including the installation of pollution controls, purchase of emission allowances, or the curtailment of operations. To date, Congress has not enacted the Clear Skies Act.

In response to Congressional inaction on the proposed Clear Skies Act, the Environmental Protection Agency (EPA) in December 2003 proposed the Interstate Air Quality Rule, which would require reductions in NOx and SO_2 similar to those found in the Clear Skies Act. However, in contrast to the Clear Skies Act, the Interstate Air Quality Rule affects emissions in 29 states in the eastern U.S., including Texas. As with the Clear Skies Act, emissions are reduced in two phases, and the reduction targets are similar, but are effective in 2010 and 2015 for both NOx and SO_2. EPA has announced an intent to finalize these rules in late 2004 or early 2005.

In December 2003, EPA proposed two alternatives for regulating emissions of mercury from coal-fired power plants in the U.S. A final rulemaking is scheduled to be adopted in December 2004. Under the first option, the EPA would set Maximum Achievable Control Technology (MACT) standards under Section 112 of the Clean Air Act, which would require mercury reductions on a facility-by-facility basis regardless of cost. The MACT standard requires reductions to be achieved by 2008, although it is possible that this compliance date will be delayed. The second option would regulate coal-fired power plants under Section 111 of the Clean

Air Act. Under this option, similar mercury reductions would be achieved on a national scale through a cap-and-trade program, allowing reductions to be made at the most economical locations, and not requiring reductions on a facility-by-facility basis. The MACT standard would require a reduction of about 30% from coal-fired facilities, which will require the installation of control equipment. The cap-and-trade rule would require deeper reductions, but may be more economical because it allows trading of emissions among facilities. The mercury cap-and-trade rule would be accomplished in two phases, in 2010 and 2015, with reduction levels set at approximately 50% and 70%, respectively. The cost of complying with the final rules is not yet known but is likely to be material.

In addition to mercury control from coal-fired boilers, the MACT rule, if adopted, would require the control of nickel emissions from oil-fired facilities. At this point, the impact of this proposal is uncertain, but is not expected to significantly affect our operations.

The EPA has also issued MACT standards for sources other than boilers used for power generation. The MACT rule for combustion turbines was issued in August 2003 and there is no impact on our existing facilities. The MACT rulemaking for engines and industrial boilers was issued in February 2004. These rules are not expected to have a significant impact on Texas Genco's operations.

Water

On February 16, 2004, the EPA signed final rules under Section 316(b) of the Clean Water Act relating to the design and operation of existing cooling water intake structures. The requirements to achieve compliance with this rule are subject to various factors, including the results of anticipated litigation, but we currently do not expect any capital expenditures required for compliance to be material.

The EPA and State of Texas periodically modify water quality standards and, where necessary, initiate total maximum daily load allocations for water bodies not meeting those standards. Such actions could cause our facilities to incur significant costs to comply with revised discharge permit limitations.

Nuclear Waste

Under the U.S. Nuclear Waste Policy Act of 1982, the federal government was to create a federal repository for spent nuclear fuel produced by nuclear plants like the South Texas Project. Also pursuant to that legislation a special assessment has been imposed on those nuclear plants to pay for the facility. Consistent with the Act, owners of nuclear facilities, including us and the other owners of the South Texas Project, entered into contracts setting out the obligations of the owners and U.S. Department of Energy (DOE). Since 1998, DOE has been in default on its obligations to begin moving spent nuclear fuel from reactors to the federal repository (which still is not completed). On January 28, 2004, we and the other owners of the South Texas Project, along with owners of other nuclear plants, filed a breach of contract suit against DOE in order to protect against the running of a statute of limitations.

Asbestos

As a result of their age, many of our facilities contain significant amounts of asbestos insulation, other asbestos-containing materials and lead-based paint. Existing state and federal rules require the proper management and disposal of these potentially toxic materials. We have developed a management plan that includes proper maintenance of existing non-friable asbestos installations, and removal and abatement of asbestos containing materials where necessary because of maintenance, repairs, replacement or damage to the asbestos itself. We have planned for the proper management, abatement and disposal of asbestos and lead-based paint at our facilities.

Our facilities are the subject of a number of lawsuits filed by a large number of individuals who claim injury due to exposure to asbestos while working at sites along the Texas Gulf Coast. Most of these claimants have been third party workers who participated in construction of various industrial facilities, including power plants, and some of the claimants have worked at locations owned by us. We anticipate that additional claims

like those received may be asserted in the future, and we intend to continue our practice of vigorously contesting claims that we do not consider to have merit.

EMPLOYEES

As of December 31, 2003, we employed 1,511 people. Of these employees, 1,030 were covered by a collective bargaining agreement with the International Brotherhood of Electrical Workers Local 66 that expired in September 2003. Our bargaining unit employees have continued to work without interruption and we have not had any work interruptions since 1976. We continue to have a good relationship with the bargaining unit and we are actively negotiating to obtain a new agreement in 2004.

EXECUTIVE OFFICERS
(As of March 1, 2004)

Name	Age	Position
David M. McClanahan	54	Chairman and Director
David G. Tees	59	President, Chief Executive Officer and Director
Scott E. Rozzell	54	Executive Vice President, General Counsel, Corporate Secretary and Director
Gary L. Whitlock	54	Executive Vice President, Chief Financial Officer and Director
James S. Brian	56	Senior Vice President and Chief Accounting Officer
Joseph B. McGoldrick	50	Corporate Vice President, Strategic Planning

David M. McClanahan is the Chairman of our board of directors. Mr. McClanahan has also served on the board of directors and as the President and Chief Executive Officer of CenterPoint Energy since September 2002. He served as the Vice Chairman of Reliant Energy from October 2000 to September 2002 and as President and Chief Operating Officer of Reliant Energy's Delivery Group since 1999. He also served as the President and Chief Operating Officer of Reliant Energy HL&P from 1997 to 1999. He has served in various other executive capacities with CenterPoint Energy since 1986. He previously served as Chairman of the Board of Directors of ERCOT and Chairman of the Board of the University of St. Thomas. He currently serves on the boards of the Edison Electric Institute and the American Gas Association.

David G. Tees is our President and Chief Executive Officer and a member of our board of directors. He served as Senior Vice President, Generation Operations of Reliant Energy from 1998 through August 2002. He also served as Vice President of Energy Production of Reliant Energy HL&P from 1986 through 1998. Mr. Tees has also served on the executive committee of the Edison Electric Institute Energy Supply Subcommittee and presently represents CenterPoint Energy as a Research Advisory Committee Member of the Electric Power Research Institute and is the Chairman of the Board of the STP Nuclear Operating Company.

Scott E. Rozzell is our Executive Vice President, General Counsel and Corporate Secretary and a member of our board of directors. Mr. Rozzell has also served as the Executive Vice President, General Counsel and Corporate Secretary of CenterPoint Energy since September 2002. He served as Executive Vice President and General Counsel of the Delivery Group of Reliant Energy from March 2001 to September 2002. Prior to joining Reliant Energy, Mr. Rozzell was a senior partner in the law firm of Baker Botts L.L.P.

Gary L. Whitlock is our Executive Vice President and Chief Financial Officer and a member of our board of directors. Mr. Whitlock has also served as the Executive Vice President and Chief Financial Officer of CenterPoint Energy since September 2002. He served as Executive Vice President and Chief Financial Officer of the Delivery Group of Reliant Energy from July 2001 to September 2002. Mr. Whitlock served as the Vice President, Finance and Chief Financial Officer of Dow AgroSciences, a subsidiary of The Dow Chemical Company from 1998 to 2001.

James S. Brian is our Senior Vice President and Chief Accounting Officer. Mr. Brian has also served as the Senior Vice President and Chief Accounting Officer of CenterPoint Energy since August 2002. He served as Senior Vice President, Finance and Administration of the Delivery Group of Reliant Energy from 1999 to August 2002, and as Vice President and Chief Financial Officer of Reliant Energy HL&P from 1997 to 1999. He has served in various executive capacities with Reliant Energy since 1983.

Joseph B. McGoldrick is our Corporate Vice President, Strategic Planning. Mr. McGoldrick has also served as Corporate Vice President, Strategic Planning of CenterPoint Energy since September 2002. He served as Corporate Vice President, Strategic Planning of the Delivery Group of Reliant Energy from November 2001 to August 2002. He served as Senior Vice President, Finance & Administration for Reliant Energy Retail from 2000 to 2001. He has served in various executive capacities with Reliant Energy since 1993.

RISK FACTORS

Market Risks

Our revenues and results of operations are impacted by market risks that are beyond our control.

We sell electric generation capacity, energy and ancillary services in the ERCOT market. Under the Texas electric restructuring law, we and other power generators in Texas are not subject to traditional cost-based regulation and therefore may sell electric generation capacity, energy and ancillary services to wholesale purchasers at prices determined by the market. As a result, we are not guaranteed any rate of return on our capital investments through mandated rates, and our revenues and results of operations depend, in large part, upon prevailing market prices for electricity in the ERCOT market. Market prices for electricity, generation capacity, energy and ancillary services may fluctuate substantially. Our gross margins are primarily derived from the sale of capacity entitlements associated with our large, solid fuel base-load generating units, including our Limestone and W. A. Parish facilities and our interest in the South Texas Project. The gross margins generated from payments associated with the capacity of these units are directly impacted by natural gas prices. Since the fuel costs for our base-load units are largely fixed under long-term contracts, they are generally not subject to significant daily and monthly fluctuations. Because natural gas is the marginal fuel for facilities serving the ERCOT market during most hours, gas prices have a significant influence on the price of electric power. As a result, the price customers are willing to pay for entitlements to our solid fuel-fired base-load capacity generally rises and falls with natural gas prices.

Market prices in the ERCOT market may also fluctuate substantially due to other factors. Such fluctuations may occur over relatively short periods of time. Volatility in market prices may result from:

- oversupply or undersupply of generation capacity;
- power transmission or fuel transportation constraints or inefficiencies;
- weather conditions;
- seasonality;
- availability and market prices for natural gas, crude oil and refined products, coal, lignite, enriched uranium and uranium fuels;
- changes in electricity usage;
- additional supplies of electricity from existing competitors or new market entrants as a result of the development of new generation facilities or additional transmission capacity;
- illiquidity in the ERCOT market;
- availability of competitively priced alternative energy sources;

- natural disasters, wars, embargoes, terrorist attacks and other catastrophic events; and
- federal and state energy and environmental regulation and legislation.

There is currently a surplus of generating capacity in the ERCOT market and we expect the market for wholesale power to be highly competitive.

The reserve margin in the ERCOT market has exceeded 30% since 2001, and the Texas Utility Commission and the ERCOT ISO have forecasted the reserve margin for 2004 to continue to exceed 30%. The commencement of commercial operation of new facilities in the ERCOT market has increased and will continue to increase the competitiveness of the wholesale power market, which could have a material adverse effect on our business, results of operations, financial condition and cash flows and the market value of our assets.

Our competitors include generation companies affiliated with Texas-based utilities, independent power producers, municipal and co-operative generators and wholesale power marketers. The unbundling of vertically integrated utilities into separate generation, transmission and distribution and retail businesses pursuant to the Texas electric restructuring law could result in a significant number of additional competitors participating in the ERCOT market. Some of our competitors may have greater financial resources, lower cost structures, more effective risk management policies and procedures, greater ability to incur losses, greater potential for profitability from ancillary services, or greater flexibility in the timing of their sale of generating capacity and ancillary services than we do.

We are subject to operational and market risks associated with our capacity auctions.

We have sold entitlements to a significant portion of our available 2004 and 2005 generating capacity in our capacity auctions held to date. Although our obligation to conduct contractually-mandated auctions terminated in January 2004, we currently remain obligated to sell 15% of our installed generation capacity and related ancillary services pursuant to state-mandated auctions and we expect to conduct future capacity auctions with respect to all or a part of our remaining capacity from time to time. In these auctions, we sell firm entitlements on a forward basis to capacity and ancillary services dispatched within specified operational constraints. Although we have reserved a portion of our aggregate net generation capacity from our capacity auctions for planned or forced outages at our facilities, unanticipated plant outages or other problems with our generation facilities could result in our firm capacity and ancillary services commitments exceeding our available generation capacity. As a result, an unexpected outage at one of our lower cost facilities could require us to run one of our higher cost plants or obtain replacement power from third parties in the open market in order to satisfy our obligations even though the energy payments for the dispatched power are based on the cost of our lower-cost facilities.

Operating Risks

The operation of our power generation facilities involves risks that could adversely affect our revenues, costs, results of operations and cash flows.

General. We are subject to various risks associated with operating our power generation facilities, any of which could adversely affect our revenues, costs, results of operations, financial condition and cash flows. These risks include:

- operating performance below expected levels of output or efficiency;
- breakdown or failure of equipment or processes;
- disruptions in the transmission of electricity;
- shortages of equipment, material or labor;
- labor disputes;

- fuel supply interruptions;
- limitations that may be imposed by regulatory requirements, including, among others, environmental standards;
- limitations imposed by the ERCOT ISO;
- violations of permit limitations;
- operator error; and
- catastrophic events such as fires, hurricanes, explosions, floods, terrorist attacks or other similar occurrences.

A significant portion of our facilities was constructed many years ago. Older generation equipment, even if maintained in accordance with good engineering practices, may require significant capital expenditures to keep it operating at high efficiency and to meet regulatory requirements. This equipment is also likely to require periodic upgrading and improvement. Any unexpected failure to produce power, including failure caused by breakdown or forced outage, could result in reduced earnings.

The cost of repairing damage to our facilities due to storms, natural disasters, wars, terrorist acts and other catastrophic events may adversely impact our results of operations, financial condition and cash flows. The occurrence or risk of occurrence of future terrorist activity may impact our results of operations and financial condition in unpredictable ways. These actions could also result in adverse changes in the insurance markets and disruptions of power and fuel markets. In addition, our power generation facilities and fuel supply could be directly or indirectly harmed by future terrorist activity. The occurrence or risk of occurrence of future terrorist attacks or related acts of war could also adversely affect the United States economy. A lower level of economic activity could result in a decline in energy consumption, which could adversely affect our revenues and margins and limit our future growth prospects. Also, these risks could cause instability in the financial markets and adversely affect our ability to access capital.

We employ experienced personnel to maintain and operate our facilities and carry insurance to mitigate the effects of some of the operating risks described above. Our insurance policies, however, are subject to certain limits and deductibles and do not include business interruption coverage. Should one or more of the events described above occur, revenues from our operations may be significantly reduced or our costs of operations may significantly increase.

In December 2003, one of the three auxiliary standby diesel generators for Unit 2 at the South Texas Project failed during a routine test. The NRC allowed continued operation of Unit 2 while repairs to the generator were made. Repairs are expected to be completed before the end of a scheduled refueling outage on the unit in the spring of 2004. Should Unit 2 experience an unplanned shutdown prior to its scheduled outage, there is a risk that the NRC would not permit restarting the unit until the diesel generator was fully repaired. Our share of the ultimate cost of repairs to the diesel generator is estimated to be approximately $5 million and is expected to be substantially covered by insurance.

We rely on power transmission facilities that we do not own or control and are subject to transmission constraints within the ERCOT market. If these facilities fail to provide us with adequate transmission capacity, we may not be able to deliver wholesale electric power to our customers and we may incur additional costs.

We depend on transmission and distribution facilities owned and operated by our affiliate, CenterPoint Houston, and on transmission and distribution systems owned by others to deliver the wholesale electric power we sell from our power generation facilities to our customers, who in turn deliver power to the end users. If transmission is disrupted, or if transmission capacity infrastructure is inadequate, our ability to sell and deliver wholesale electric energy may be adversely impacted.

The single control area of the ERCOT market for 2004 is organized into five congestion zones, referred to as the North, Northeast, South, West and Houston zones. These congestion zones are determined by physical

constraints on the ERCOT transmission system that make it difficult or impossible at times to move power from a zone on one side of the constraint to the zone on the other side of the constraint. All but two of our facilities are located in the Houston congestion zone. Our Limestone facility is located in the North congestion zone and the South Texas Project is located in the South congestion zone. We sell a portion of the entitlements offered in our state-mandated auctions to customers located in congestion zones other than the Houston zone. Transmission congestion between these zones could impair our ability to schedule power for transmission across zonal boundaries, which are defined by the ERCOT ISO, thereby inhibiting our efforts to match our facility scheduled outputs with our customer scheduled requirements.

The ERCOT ISO has instituted rules that directly assign congestion costs to the parties causing the congestion. Therefore, power generators participating in the ERCOT market could be liable for the congestion costs associated with transferring power between zones. We schedule our anticipated requirements based on our own forecasted needs, which rely in part on demand forecasts made by our customers. These forecasts may prove to be inaccurate. We could be deemed responsible for congestion costs if we schedule delivery of power between congestion zones during times when the ERCOT ISO expects congestion to occur between the zones. If we are liable for congestion costs, our financial results could be adversely affected. For more information about the ERCOT market, please read "Our Business — The ERCOT Market" above.

Our results of operations, financial condition and cash flows could be adversely impacted by a disruption of our fuel supplies.

We rely primarily on natural gas, coal, lignite and uranium to fuel our generation facilities. We purchase our fuel from a number of different suppliers under long-term contracts and on the spot market. We sell firm entitlements to capacity and ancillary services. Therefore, any disruption in the delivery of fuel could prevent us from operating our facilities to meet our auction commitments, which could adversely affect our results of operations, financial condition and cash flows.

Delivery of natural gas to each of our natural gas-fired facilities typically depends on the natural gas pipelines or distributors for that location. As a result, we are subject to the risk that a natural gas pipeline or distributor may suffer disruptions or curtailments in our ability to deliver natural gas to it or that the amounts of natural gas we request are curtailed. These disruptions or curtailments could adversely affect our ability to operate our natural gas-fired generating facilities. We lease gas storage facilities capable of storing approximately 6.3 billion cubic feet of natural gas, of which 4.2 billion cubic feet is working capacity.

We purchase coal from a limited number of suppliers. Generally, we seek to maintain average coal reserves sufficient to operate our coal-fired facilities for 30 days. We also have long-term rail transportation contracts with two rail transportation companies to transport coal to our coal-fired facilities. Any extended disruption in our coal supply, including those caused by transportation disruptions, adverse weather conditions, labor relations or environmental regulations affecting our coal suppliers, could adversely affect our ability to operate our coal-fired facilities. We are also exposed to the risk that suppliers that have agreed to provide us with fuel could breach their obligations. Should these suppliers fail to perform, we may be forced to enter into alternative arrangements at then-current market prices. As a result, our results of operations, financial condition and cash flows could be adversely affected.

To date, we have sold a substantial portion of our auctioned capacity entitlements to subsidiaries of Reliant Resources. Accordingly, our results of operations, financial condition and cash flows could be adversely affected if Reliant Resources ceases to be a major customer or fails to meet its obligations.

By participating in our contractually-mandated auctions, subsidiaries of Reliant Resources have purchased entitlements to 79% of our sold 2004 capacity and 68% of our sold 2005 capacity. Reliant Resources has made these purchases either through the exercise of its contractual rights to purchase 50% of the entitlements we auctioned in our prior contractually-mandated auctions or through the submission of bids. In the event Reliant Resources ceases to be a major customer or fails to meet its obligations to us, our results of operations, financial condition and cash flows could be adversely affected. As of December 31, 2003, Reliant Resources' securities ratings are below investment grade. We have been granted a security interest in accounts

receivable and/or securitization notes associated with the accounts receivable of certain subsidiaries of Reliant Resources to secure up to $250 million in purchase obligations.

We may incur substantial costs and liabilities as a result of our ownership of nuclear facilities.

We own a 30.8% interest in the South Texas Project, a nuclear powered generation facility. As a result, we are subject to the risks associated with the ownership and operation of nuclear facilities. These risks include:

- liabilities associated with the potential harmful effects on the environment and human health resulting from the operation of nuclear facilities and the storage, handling and disposal of radioactive materials;
- limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with nuclear operations; and
- uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of their licensed lives.

The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities. In the event of non-compliance, the NRC has the authority to impose fines, shut down a unit, or both, depending upon our assessment of the severity of the situation, until compliance is achieved. Revised safety requirements promulgated by the NRC could necessitate substantial capital expenditures at nuclear plants. In addition, although we have no reason to anticipate a serious nuclear incident at the South Texas Project, if an incident were to occur, it could have a material adverse effect on our results of operations, financial condition and cash flows.

Other Risks

Our historical financial results covering periods prior to 2002 represent our results as part of an integrated utility operating in a regulated market and are not representative of our results as a separate company operating in the deregulated ERCOT market. Consequently, our future financial condition and results of operations are likely to vary materially from the financial condition and results of operations presented in the historical financial information included herein covering periods prior to 2002.

We have limited experience operating as a stand-alone wholesale electric power generation company in a deregulated market. Our generation facilities were formerly owned by Reliant Energy, which conveyed these facilities to us in accordance with a business separation plan adopted in response to the Texas electric restructuring law.

The historical financial information covering periods prior to 2002 does not reflect what our financial position, results of operations and cash flows would have been had our generation facilities been operated under the current deregulated ERCOT market. Although our generation facilities had a significant operating history at the time they were conveyed to us, the historical financial information relating to the operation of these facilities during periods prior to 2002 reflects the sale of the power generated by the facilities as part of an integrated utility at regulated rates. We currently sell the power generated by these facilities at market-based prices, and our revenues currently depend, in large part, upon prevailing market prices for electricity in the ERCOT market. To date, our capacity auctions have been consummated at market-based prices that have resulted in returns substantially below the historical regulated return on our facilities.

The historical financial information we have included herein also does not reflect what our financial position, results of operations and cash flows would have been had we been a separate entity during the periods presented. Our historical costs and expenses included in our financial statements reflect charges from Reliant Energy for centralized corporate services and operating infrastructure costs as well as allocated costs of capital. These allocations have been determined based on what we and Reliant Energy considered to be reasonable reflections of the utilization of services provided to us or for the benefits received by us. We may experience significant changes in our cost structure, capitalization and operations as a result of our separation from

Reliant Energy, including increased costs associated with reduced economies of scale and with being a publicly traded company.

We may not have access to sufficient capital in the amounts and at the times needed to finance our business.

To date, our capital has been provided by internally generated cash flows and borrowings from the CenterPoint Energy money pool. As a result of our certification by the FERC as an "exempt wholesale generator" under the 1935 Act, we can no longer participate in this money pool. CenterPoint Energy has established a second money pool in which Texas Genco and certain other unregulated subsidiaries of CenterPoint Energy can participate. In December 2003, we entered into a $75 million revolving credit facility. It is anticipated that we will meet our cash needs with a combination of funds from operations and borrowings under our revolving credit facility. Except in an emergency situation (in which CenterPoint Energy could provide funding pursuant to applicable SEC rules), CenterPoint Energy would be required to obtain approval from the SEC to issue and sell securities for purposes of funding our operations or for CenterPoint Energy to guarantee our securities. There is no assurance that CenterPoint Energy will have sufficient funds to meet our cash needs.

CenterPoint Energy's $2.3 billion bank facility limits our incurrence of indebtedness for borrowed money to an aggregate principal amount not to exceed $250 million outstanding at any time and requires that proceeds from the sale of any material portion of our assets, proportionate to CenterPoint Energy's ownership interest in us and subject to certain other requirements, be used to prepay indebtedness under such credit facility. Our new credit facility also limits our incurrence of additional secured indebtedness for borrowed money to a maximum of $175 million aggregate principal amount. Although we are not contractually bound by the limitations in CenterPoint Energy's bank facility, it is expected that CenterPoint Energy would likely cause its representatives on our board of directors to direct our business so as not to breach the terms of its facility.

We can give no assurances that our current and future capital structure, operating performance, financial condition and cash flows will permit us to access the capital markets or to obtain other financing as needed to meet our working capital requirements and projected future capital expenditures on favorable terms. The amount of any debt issuance by us is expected to be affected by the market's perception of our creditworthiness, market conditions and factors affecting our industry. Our projected future capital expenditures are substantial. Our ability to secure third party credit lines or other debt financing may be adversely impacted by the factors described in this section, including the nature of our business, which may lead to volatility in our financial results and cash flows. Please read "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Future Sources and Uses of Cash," in Item 7 of this report.

We are an 81% owned subsidiary of CenterPoint Energy. As a result of this relationship, the financial condition of CenterPoint Energy could affect our access to capital, our credit standing and our financial condition.

Our operations are subject to extensive regulation, including environmental regulation. If we fail to comply with applicable regulations or obtain or maintain any necessary governmental permit or approval, we may be subject to civil, administrative and/or criminal penalties that could adversely impact our results of operations, financial condition and cash flows.

Our operations are subject to complex and stringent energy, environmental and other governmental laws and regulations. The acquisition, ownership and operation of power generation facilities require numerous permits, approvals and certificates from federal, state and local governmental agencies. These facilities are subject to regulation by the Texas Utility Commission regarding non-rate matters. Existing regulations may be revised or reinterpreted, new laws and regulations may be adopted or become applicable to us or any of our generation facilities or future changes in laws and regulations may have a detrimental effect on our business.

Operation of the South Texas Project is subject to regulation by the NRC. This regulation involves testing, evaluation and modification of all aspects of plant operation in light of NRC safety and environmental requirements. Continuous demonstrations to the NRC that plant operations meet applicable requirements are also required. The NRC has the ultimate authority to determine whether any nuclear powered generating unit may operate.

Water for certain of our facilities is obtained from public water authorities. New or revised interpretations of existing agreements by those authorities or changes in price or availability of water may have a detrimental effect on our business.

Our business is subject to extensive environmental regulation by federal, state and local authorities. We are required to comply with numerous environmental laws and regulations and to obtain numerous governmental permits in operating our facilities. We may incur significant additional costs to comply with these requirements. If we fail to comply with these requirements or with any other regulatory requirements that apply to our operations, we could be subject to administrative, civil and/or criminal liability and fines, and regulatory agencies could take other actions seeking to curtail our operations. These liabilities or actions could adversely impact our results of operations, financial condition and cash flows.

Existing environmental regulations could be revised or reinterpreted, new laws and regulations could be adopted or become applicable to us or our facilities, and future changes in environmental laws and regulations could occur, including potential regulatory and enforcement developments related to air emissions. If any of these events occurs, our business, results of operations, financial condition and cash flows could be adversely affected.

We may not be able to obtain or maintain from time to time all required environmental regulatory approvals. If there is a delay in obtaining any required environmental regulatory approvals or if we fail to obtain and comply with them, we may not be able to operate our facilities or we may be required to incur additional costs. We are generally responsible for all on-site liabilities associated with the environmental condition of our power generation facilities, regardless of when the liabilities arose and whether the liabilities are known or unknown. These liabilities may be substantial.

Our insurance coverage may not be sufficient. Insufficient insurance coverage and increased insurance costs could adversely impact our results of operations, financial condition and cash flows.

We have insurance covering certain of our facilities, including property damage insurance, commercial general liability insurance, boiler and machinery coverage and available replacement capacity in amounts that we consider appropriate. However, our insurance policies are subject to certain limits and deductibles and do not include business interruption coverage. We cannot assure you that insurance coverage will be available in the future at current costs or on commercially reasonable terms or that the insurance proceeds received for any loss of or any damage to any of our generation facilities will be sufficient to restore the loss or damage without negative impact on our results of operations, financial condition and cash flows.

We and the other owners of the South Texas Project maintain nuclear property and nuclear liability insurance coverage as required by law and periodically review available limits and coverage for additional protection. The owners of the South Texas Project currently maintain $2.75 billion in property damage insurance coverage, which is above the legally required minimum, but is less than the total amount of insurance currently available for such losses. Under the federal Price Anderson Act, the maximum liability to the public of owners of nuclear power plants was $10.6 billion as of December 31, 2003. Owners are required under the Price Anderson Act to insure their liability for nuclear incidents and protective evacuations. We and the other owners of the South Texas Project currently maintain the required nuclear liability insurance and participate in the industry retrospective rating plan. In addition, the security procedures at this facility have recently been enhanced to provide additional protection against terrorist attacks. All potential losses or liabilities associated with the South Texas Project may not be insurable, and the amount of insurance may not be sufficient to cover them.

Our revenues and results of operations are seasonal.

The demand for power in the ERCOT market is seasonal, with higher demand occurring during the warmer months. Accordingly, our customers are generally willing to pay higher prices for entitlements to our capacity during warmer months. As a result, our revenues and results of operations are subject to seasonality, with revenues being higher during the warmer months.

Risks Related to Our Relationships With CenterPoint Energy

CenterPoint Energy's plan to monetize its interest in us may adversely impact our operations and financial condition, and the trading price of Texas Genco's common stock.

CenterPoint Energy expects to monetize its 81% interest in Texas Genco in 2004 and has engaged a financial advisor to assist them in that pursuit. CenterPoint Energy plans to fully evaluate this option before seeking another alternative. CenterPoint Energy and Reliant Resources currently provide a variety of services to us pursuant to the agreements described under "Management's Discussion and Analysis of Financial Condition and Results of Operations — Related Party Transactions — Our Relationships with CenterPoint Energy" and "— Technical Services Agreement with Reliant Resources" in Item 7 of this report. These services agreements will terminate upon the sale of CenterPoint Energy's interest in Texas Genco. In such an event, we may be required to replace the services currently provided under arrangements with less favorable terms. Also, under the terms of our $75 million 365-day revolving credit facility, if CenterPoint Energy ceases to own, directly or indirectly, at least a 50% voting and economic interest in our wholly owned subsidiary Texas Genco, LP, an event of default will occur and any borrowings thereunder may become immediately due and payable. In addition, depending on the nature of any monetization transaction, the trading price of Texas Genco's common stock could be adversely affected.

We will be controlled by CenterPoint Energy as long as it owns a majority of Texas Genco's common stock, and our minority shareholders will be unable to affect the outcome of shareholder voting during that time.

As a result of the January 6, 2003 distribution, CenterPoint Energy indirectly owns approximately 81% of Texas Genco's outstanding common stock. As long as CenterPoint Energy owns a majority of our outstanding common stock, it will continue to be able to elect our entire board of directors, and our public shareholders, by themselves, will not be able to affect the outcome of any shareholder vote. In addition, CenterPoint Energy has stated that it is pursuing strategic alternatives for its ownership interest in us, including a possible sale, which could result in a third party becoming our majority shareholder. Our majority shareholder, subject to any fiduciary duty owed to our minority shareholders under Texas law, will be able to control all matters affecting us. In addition, our majority shareholder may enter into credit agreements, indentures or other contracts that limit the activities of its subsidiaries. While we would not likely be contractually bound by these limitations, our majority shareholder would likely cause its representatives on our board to direct our business so as not to breach any of these agreements.

We may have potential business conflicts of interest with CenterPoint Energy with respect to our past and ongoing relationships, and because of CenterPoint Energy's controlling ownership interest, we may not be able to resolve these conflicts on terms possible in arm's length transactions.

Conflicts of interest may arise between CenterPoint Energy and us in a number of areas relating to our past and ongoing relationships, including proceedings, actions and decisions of legislative bodies and administrative agencies, and our dividend policy. The agreements we have entered into with CenterPoint Energy may be amended in the future upon agreement of the parties. While we are controlled by CenterPoint Energy, CenterPoint Energy may be able to require us to amend these agreements. We may not be able to resolve any potential conflicts with CenterPoint Energy, and even if we do, the resolution may be less favorable than if we were dealing with an unaffiliated party.

Item 2. *Properties.*

Our central support facility includes office space, a maintenance shop, a chemical lab, a warehouse facility and a fleet maintenance garage. This facility includes a total of approximately 521,000 square feet of space, of which approximately 407,000 square feet is occupied by us and approximately 114,000 square feet is leased to Reliant Resources. We also lease approximately 7,100 square feet at CenterPoint Energy's principal office building.

In addition, we lease or own various real property and facilities relating to our generation assets and other vacant real property unrelated to our generation assets. We have described our principal generation and support facilities under "Our Generation Portfolio" in Item 1 of this report, which description is incorporated herein by reference. We believe we have satisfactory title to our facilities in accordance with standards generally accepted in the electric power industry, subject to exceptions that, in our opinion, would not have a material adverse effect on the use or value of the facilities.

All of our real and tangible properties, subject to certain exclusions, are currently subject to the lien of a First Mortgage Indenture (the Mortgage) dated December 23, 2003 between JPMorgan Chase Bank, as trustee, and our wholly owned subsidiary, Texas Genco, LP. As of December 31, 2003, we had issued $75 million aggregate principal amount of first mortgage bonds under the Mortgage as collateral to secure our obligations under our $75 million 364-day revolving credit facility.

Item 3. *Legal Proceedings.*

We are, from time to time, a party to litigation arising in the normal course of our business, most of which involves contract disputes or claims for personal injury and property damage incurred in connection with our operations. We are not currently involved in any litigation that we expect will have a material adverse effect on our financial condition, results of operations and cash flows. For a description of a number of lawsuits involving claims of asbestos exposure at properties owned by us, please read "Environmental Matters — Asbestos" in Item 1 of this report, which description is incorporated herein by reference.

During 2003, we and CenterPoint Energy were engaged in a dispute with Northwestern Resources Co. (NWR), the supplier of fuel to the Limestone electric generation facility, over the terms and pricing at which NWR supplies fuel to that facility under a 1999 settlement agreement between the parties and under ancillary obligations. Both sides to the dispute initiated lawsuits, but in January 2004, we reached a settlement with NWR under which we agreed to dismiss those lawsuits and under which NWR would continue to provide certain quantities of lignite at specified prices during the period from 2004 to 2007, after which time the pricing would revert to pricing provided for under the 1999 settlement.

Item 4. *Submission of Matters to a Vote of Security Holders.*

There were no matters submitted to the vote of our security holders during the fourth quarter of 2003.

PART II

Item 5. *Market for Common Stock and Related Stockholder Matters.*

As of February 29, 2004, Texas Genco's common stock was held by approximately 51,362 shareholders of record. Texas Genco's common stock is listed on the New York Stock Exchange and is traded under the symbol "TGN."

On January 6, 2003, CenterPoint Energy distributed approximately 19% of the 80 million outstanding shares of Texas Genco common stock to CenterPoint Energy's shareholders of record as of the close of business on December 20, 2002, the record date for the distribution. Our common stock began trading regular-way on the New York Stock Exchange on January 7, 2003. Accordingly, no high and low sales price information is available for any full quarterly period in 2002.

The following table sets forth the high and low sales prices of the common stock of Texas Genco on the New York Stock Exchange composite tape during the periods indicated, as reported by *Bloomberg*, and the cash dividends declared in these periods. Cash dividends paid aggregated $1.00 per share in 2003.

	Market Price		Dividend Declared Per Share
	High	Low	
2003			
First Quarter			$0.25
January 7		$10.50	
March 10	$18.58		
Second Quarter			$0.25
April 21		$16.20	
June 19	$23.99		
Third Quarter			$0.25
July 22		$21.56	
September 2	$25.70		
Fourth Quarter			$0.25
October 3		$23.40	
December 22	$32.71		

The closing market price of our common stock on December 31, 2003 was $32.50 per share.

While we intend to pay regular quarterly cash dividends on our common stock, our board of directors will determine the amount of future dividends in light of:

- applicable legal requirements;
- our earnings and cash flows;
- our financial condition; and
- other factors our board of directors deems relevant.

CenterPoint Energy currently owns approximately 81% of Texas Genco's outstanding common stock which has been pledged to secure any obligations of CenterPoint Energy under its $2.3 billion credit facility executed in October 2003.

Item 6. *Selected Financial Data.*

The following tables present our selected financial data. The data set forth below should be read together with "Management's Discussion and Analysis of Financial Condition and Results of Operations," and our historical financial statements and the notes to those statements included in this report. Our selected financial data for each of the five years in the period ended December 31, 2003 are derived from our financial statements. Our financial statements for periods prior to January 1, 2002 are presented on a carve-out basis and represent the historical financial position, results of operations and net cash flows of the historically regulated generation-related business of Reliant Energy. Therefore, the historical information included in our financial statements is not indicative of our future performance and does not reflect what our financial position and results of operations would have been had we operated as a separate, stand-alone wholesale electric power generation company in a deregulated market during the periods presented. Prior to January 1, 2002, our historical financial information reflects the sale of power generated by our facilities as part of an integrated utility at regulated rates. Since January 1, 2002, we have sold power at market-based prices in capacity auctions. In addition, our historical costs and expenses reflect charges from CenterPoint Energy for centralized corporate services and operating infrastructure costs as well as allocated costs of capital through August 31, 2002. We may experience significant changes in our cost structure, capitalization and operations as a result of our separation from CenterPoint Energy, including increased costs associated with reduced economies of scale, obtaining third-party financing and being a publicly traded company.

	Year Ended December 31,				
	1999	2000	2001	2002	2003
			(In millions)		
Income Statement Data:					
Revenues	$2,816	$3,334	$3,411	$1,541	$2,002
Expenses:					
Fuel costs	1,170	1,644	1,304	989	1,098
Purchased power	395	753	1,223	94	73
Operation and maintenance	384	393	402	391	411
Depreciation and amortization	393	151	154	157	159
Taxes other than income taxes	79	63	63	43	39
Total	2,421	3,004	3,146	1,674	1,780
Operating Income (Loss)	395	330	265	(133)	222
Other Income	14	1	2	3	2
Interest Expense, net	71	59	65	26	2
Income (Loss) Before Income Taxes and Extraordinary Item	338	272	202	(156)	222
Income Tax Expense (Benefit)	113	100	74	(63)	71
Income (Loss) Before Extraordinary Item	225	172	128	(93)	151
Extraordinary Item, net of tax(1)	(518)	—	—	—	—
Cumulative Effect of Accounting Change, net of tax(2)	—	—	—	—	99
Net Income (Loss)	$ (293)	$ 172	$ 128	$ (93)	$ 250
Income (Loss) Before Cumulative Effect of Accounting Change	$(3.66)	$ 2.15	$ 1.60	$(1.16)	$ 1.89
Cumulative Effect of Accounting Change	—	—	—	—	1.24
Net Income (Loss)(3)	$(3.66)	$ 2.15	$ 1.60	$(1.16)	$ 3.13

(1) Represents a loss related to an accounting impairment of certain generating facilities.

(2) 2003 net income includes the cumulative effect of an accounting change resulting from the adoption of SFAS No. 143, "Accounting for Asset Retirement Obligations" ($99 million after-tax gain, or $1.24

earnings per basic and diluted share). For additional information related to the cumulative effect of accounting change, please read Note 2(j) to our consolidated financial statements.

(3) The earnings per share figures are computed by dividing the net income (loss) for each period by 80 million, the number of shares of Texas Genco common stock outstanding after the 80,000-for-one stock split declared by Texas Genco's Board of Directors, as effected on December 18, 2002.

	Year Ended December 31,		
	2001	2002	2003
	(In millions)		
Statement of Cash Flow Data:			
Cash provided by (used in):			
Operating Activities	$ 236	$(140)	$ 387
Investing Activities	(409)	(258)	(157)
Financing Activities	173	398	(186)

	December 31,				
	1999	2000	2001	2002	2003
			(In millions)		
Balance Sheet Data:					
Property, Plant and Equipment, net	$3,698	$3,782	$4,020	$4,096	$4,126
Total Assets	4,029	4,147	4,438	4,508	4,640
Capitalization(1)	2,331	2,323	2,624	—	—
Shareholders' Equity(1)	—	—	—	2,824	3,033

(1) Upon the restructuring of Reliant Energy pursuant to its business separation plan, effective August 31, 2002, our equity structure was changed to reflect the contribution of CenterPoint Energy's electric generating facilities to us.

Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations.*

The following discussion and analysis should be read in combination with our consolidated financial statements and notes contained in Item 8 herein.

OVERVIEW

We are a wholesale electric power generating company that owns 60 generating units at 11 electric power generation facilities located in Texas. We also own a 30.8% interest in the South Texas Project Electric Generating Station (South Texas Project), a nuclear generating station with two 1,250 megawatt (MW) nuclear generating units. As of December 31, 2003, the aggregate net generating capacity of our portfolio of assets was 14,153 megawatts (MW), of which 2,988 MW of gas-fired capacity was currently mothballed. We expect that 777 MW of this amount will remain mothballed through April 2004 and the other 2,211 MW will remain mothballed through April 2005. The decision to mothball these units was based on the lack of demand for these types of units in our July and September 2003 capacity auctions combined with high forecasted reserve margins in the Electric Reliability Council of Texas (ERCOT) market. We sell electric generation capacity, energy and ancillary services in the ERCOT market, which is the largest power market in the State of Texas and encompasses the majority of the population centers in the State of Texas. ERCOT facilitates reliable grid operations for approximately 85% of the demand for power in the state.

Our Separation from CenterPoint Energy

Legislation enacted by the Texas legislature in 1999 (Texas electric restructuring law) required the restructuring of electric utilities in Texas in order to separate their power generation, transmission and distribution, and retail electric provider businesses into separate units. In March 2001, the Public Utility

Commission of Texas (Texas Utility Commission) approved a business separation plan for Reliant Energy, Incorporated (Reliant Energy) involving the separation of Reliant Energy's generation, transmission and distribution, and retail businesses into three separate companies. Effective August 31, 2002, Reliant Energy consummated a restructuring transaction (the Restructuring) in accordance with its business separation plan in which it, among other things:

- conveyed all of its electric generating facilities to us;
- became a subsidiary of CenterPoint Energy, Inc. (CenterPoint Energy); and
- converted into a limited liability company named CenterPoint Energy Houston Electric, LLC (CenterPoint Houston).

Although our portfolio of generating facilities was formerly owned by the unincorporated electric utility division of Reliant Energy, for convenience we describe our business as if we had owned and operated our generation facilities prior to the date they were conveyed to us. The book value of the net assets conveyed to us by Reliant Energy on August 31, 2002 was approximately $2.8 billion.

CenterPoint Energy is a registered public utility holding company under the Public Utility Holding Company Act of 1935, as amended (1935 Act). The 1935 Act and related rules and regulations impose a number of restrictions on the activities of CenterPoint Energy and its subsidiaries. In October 2003, the Federal Energy Regulatory Commission (FERC) granted exempt wholesale generator (EWG) status to Texas Genco, LP, our wholly owned subsidiary that owns and operates our electric generating plants. As a result, we are exempt from substantially all provisions of the 1935 Act. We will remain exempt for so long as Texas Genco, LP remains an exempt wholesale generator. SEC approval would be required, however, for CenterPoint Energy to issue and sell securities for the purpose of funding our operations, or for CenterPoint Energy to guarantee our securities. Also, SEC policy precludes us from borrowing from CenterPoint Energy's utility subsidiaries.

On January 6, 2003, CenterPoint Energy distributed approximately 19% of the 80 million outstanding shares of Texas Genco's common stock to CenterPoint Energy's shareholders (the Distribution). As used herein, CenterPoint Energy also refers to the former Reliant Energy for dates prior to the Restructuring.

Our Power Generation Business

Our energy costs consist primarily of fuel costs associated with consuming nuclear fuel, gas, oil, lignite and coal to generate electricity, as well as our power purchases from the wholesale marketplace. The recent deregulation of the ERCOT market has impacted our energy costs in several ways. As a result of requirements under the Texas electric restructuring law and the terms of our agreements with CenterPoint Energy, we have been obligated to sell through capacity auctions substantially all of our available capacity and related ancillary services through 2003. Beginning in 2004, we can market the 85% of our capacity as we deem appropriate based upon market conditions, which may include a combination of auctions and bilateral contracts. In the auctions described above, we sell on a forward basis firm entitlements to capacity and ancillary services dispatched within specified operational constraints. Although we have reserved a portion of our aggregate net generation capacity from our capacity auctions for planned or forced outages at our facilities, unanticipated plant outages or other unforeseen problems with our generation facilities could result in our firm capacity and ancillary services commitments exceeding our available generation capacity. As a result, we could be required to obtain replacement power from third parties in the open market to satisfy our firm commitments that could involve the incurrence of significant additional costs. Accordingly, high wholesale power prices for replacement power in the ERCOT market could increase our energy costs and affect earnings and net cash flow. In addition, an unexpected outage at one of our lower cost facilities could require us to run one of our higher cost plants in order to satisfy our obligations which could have a significant effect on our operating income.

In 2003, the market-based prices established in our capacity auctions continued to strengthen, but remained below historical regulated returns on our facilities. However, we have seen significant improvement in auction prices for our 2003, 2004 and 2005 capacity entitlements. Since the pricing of generation products is

sensitive to natural gas prices, higher natural gas prices throughout 2003 have positively influenced the prices in our capacity auctions. Because we have a significant amount of low-cost base-load solid fuel and nuclear generating units, higher natural gas prices generally increase the margin of our base-load capacity entitlements since prospective purchasers face higher-cost gas-fired generation alternatives. With the higher market prices and our efforts to reduce our operating costs, we have experienced improved profitability during 2003 compared to 2002. However, we do not expect this improvement will reach the levels of our historical regulated returns in the near future due in part to the current surplus of generating capacity in the ERCOT market and changes to the economic conditions affecting our industry that have occurred since our base-load facilities were originally constructed, including the development of high efficiency gas-fired generating units.

High reserve margins are expected to continue in the ERCOT market. With an increasingly competitive wholesale energy market, the composition and level of our operation and maintenance expense is likely to change as we continually evaluate the value of various units based on their fuel source, heat rate and dispatch type.

We were unable to sell some of the 2003 capacity that we have offered in our state-mandated auctions. However, we believe that we have complied with the requirements under the applicable state-mandated auction rules, including re-offering the unsold capacity in subsequent auctions.

EXECUTIVE SUMMARY

2003 Highlights

In 2003, we reported net income of $250 million as compared to a net loss of $93 million in 2002. Revenues significantly increased in 2003 as compared to 2002 due to higher capacity revenue for base-load products, the sales of surplus air emission allowances and higher energy revenues, which more than offset higher fuel and purchased power costs. Operation and maintenance expenses increased primarily due to higher costs associated with planned and several unplanned unit outages as well as higher pension and insurance expenses. These increases were partially offset by expenses incurred in the fourth quarter of 2002, which did not recur in 2003, the most significant of which was an early retirement program. Net income for 2003 includes a $99 million after-tax ($152 million pre-tax) non-cash gain ($1.24 per diluted share) from the adoption of SFAS No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143) as further discussed below under "— Consolidated Results of Operations."

2004 Outlook

In our capacity auctions held through February 2004, we have sold capacity entitlements to approximately 85% of our available 2004 base-load capacity and 24% of our available 2005 base-load capacity. As a result, we have contracted for approximately $1 billion of total revenue with respect to our 2004 capacity and approximately $533 million of total revenue with respect to our 2005 capacity. We expect to conduct auctions to sell additional capacity entitlements with respect to our 2004 and 2005 capacity during March 2004. Sales of additional surplus air emission allowances are anticipated in 2004. Studies are underway to determine longer-term strategies, including selling capacity through contractual agreements as well as auctions and evaluating financial hedging policies. Financial performance in 2004 and beyond is highly dependent on continued strong wholesale electricity prices, as well as acceptable levels of planned and unplanned outages.

In December 2003, one of the three auxiliary standby diesel generators for Unit 2 at the South Texas Project failed during a routine test. The NRC allowed continued operation of Unit 2 while repairs to the generator were made. Repairs are expected to be completed before the end of a scheduled refueling outage on the unit in the spring of 2004. Should Unit 2 experience an unplanned shutdown prior to its scheduled outage, there is a risk that the NRC would not permit restarting the unit until the diesel generator was fully repaired. Our share of the ultimate cost of repairs to the diesel generator is estimated to be approximately $5 million and is expected to be substantially covered by insurance.

CERTAIN FACTORS AFFECTING FUTURE EARNINGS

Our past earnings and results of operations are not necessarily indicative of our future earnings and results of operations. Any of the following factors could adversely affect our business prospects, financial condition, operating results and cash flows:

- state and federal legislative and regulatory actions or developments, including deregulation; re-regulation and restructuring of the ERCOT market; and changes in, or application of, environmental and other laws or regulations to which we are subject;
- the timing and extent of changes in commodity prices, particularly natural gas;
- the effects of competition, including the extent and timing of the entry of additional competitors in the ERCOT market;
- the results of our capacity auctions;
- weather variations and other natural phenomena;
- financial distress of our customers, including Reliant Resources;
- our access to capital and credit; and
- other factors discussed in this report under "Risk Factors" in Item 1 of this report.

CONSOLIDATED RESULTS OF OPERATIONS

The following discussion and analysis of our results of operations have been derived from our historical financial statements and the notes to those financial statements included herein, which we refer to collectively as "our financial statements." Our financial statements were developed using a number of assumptions to separate our operations from those of Reliant Energy, which until January 1, 2002, operated our generation assets together with its transmission and distribution facilities and retail operations as a vertically integrated utility company. Please read Note 1 to our financial statements for a discussion of these assumptions and the methodologies used to prepare our financial statements. The historical financial information for 2001 included in our financial statements may not be indicative of our future performance and does not reflect what our financial position and results of operations would have been had we operated as a separate, stand-alone wholesale electric power generation company in a deregulated market during the periods presented.

Prior to January 1, 2002, our revenues were calculated by unbundling the generation component of revenue from CenterPoint Energy's historical bundled rate for the generation and transmission, distribution and sale of energy and adding any additional generation-related revenues of CenterPoint Energy, such as wholesale activities that include ancillary services, trading and capacity sales.

	Year Ended December 31,		
	2001	2002	2003
		(in thousands)	
Revenues:			
Revenues	$3,410,945	$ —	$ —
Energy revenues	—	1,093,714	1,221,348
Capacity and other revenues	—	447,261	781,020
Total	3,410,945	1,540,975	2,002,368
Expenses:			
Fuel costs	1,303,981	989,560	1,098,269
Purchased power	1,222,552	93,841	72,509
Operation and maintenance	401,677	391,465	411,940
Depreciation and amortization	154,248	156,740	159,010
Taxes other than income taxes	63,378	42,930	38,681
Total	3,145,836	1,674,536	1,780,409
Operating Income (Loss)	265,109	(133,561)	221,959
Other Income	2,100	3,423	2,176
Interest Expense	(65,017)	(25,637)	(1,583)
Income (Loss) Before Income Taxes and Cumulative Effect of Accounting Change	202,192	(155,775)	222,552
Income Tax Benefit (Expense)	(73,804)	62,832	(71,286)
Income (Loss) Before Cumulative Effect of Accounting Change	128,388	(92,943)	151,266
Cumulative Effect of Accounting Change, net of tax	—	—	98,910
Net Income (Loss)	$ 128,388	$ (92,943)	$ 250,176
Basic and Diluted Earnings Per Share:			
Income (Loss) Before Cumulative Effect of Accounting Change	$ 1.60	$ (1.16)	$ 1.89
Cumulative Effect of Accounting Change, net of tax	—	—	1.24
Net Income (Loss)	$ 1.60	$ (1.16)	$ 3.13
Power Sales (in GWh)	—	51,463	47,374

2003 Compared to 2002. Our income before cumulative effect of accounting change increased $244 million in 2003 compared to 2002 primarily due to increased operating margins ($357 million) from higher capacity and energy revenues as a result of higher capacity auction prices driven by higher natural gas prices, partially offset by increased fuel costs due to higher natural gas prices and by lower sales volumes. We were able to partially mitigate the higher cost of natural gas by switching to fuel oil on some of our flexible natural gas units, as well as benefiting from reductions in coal and lignite costs on our base-load units resulting from renegotiated supply agreements and increased utilization of spot purchases. Additionally, the sale of surplus air emission allowances, which is expected to recur in 2004, contributed to the increase in operating margins ($16 million). Partially offsetting the increase in operating margins was a higher level of operation and maintenance expense primarily related to higher pension and insurance expenses ($21 million) and planned and unplanned outages ($11 million). These increases in operation and maintenance expense were partially offset by expenses incurred in 2002, which did not recur in 2003, the most significant of which were in connection with an early retirement program and business separation costs ($28 million). Interest expense decreased $24 million in 2003 as compared to 2002 primarily due to the allocation of interest through the date of the Restructuring (August 31, 2002) based on the remaining electric utility debt not specifically identified with CenterPoint Energy's transmission and distribution utility upon deregulation, and the repayment of intercompany borrowings in 2003. Our effective tax rate for 2002 and 2003 was 40.3% and 32.0%, respectively. We reported a pre-tax loss for 2002 compared to pre-tax income for 2003. The 2002 pre-tax loss caused permanent differences that would normally decrease the effective rate to instead increase it. For 2003, our effective tax rate reflects reduced benefits from the amortization of investment tax credits.

In connection with the adoption of SFAS No. 143, we have identified retirement obligations for nuclear decommissioning at the South Texas Project and for lignite mine operations which supply the Limestone electric generation facility. The net difference between the amounts determined under SFAS No. 143 and the previous method of accounting for estimated mine reclamation costs was $37 million and has been recorded as a cumulative effect of accounting change. Upon adoption of SFAS No. 143, we reversed $115 million of previously recognized removal costs as a cumulative effect of accounting change. Net income for 2003 includes a $99 million after-tax ($152 million pre-tax) non-cash gain ($1.24 per diluted share) from the adoption of SFAS No. 143. For additional discussion of the adoption of SFAS No. 143, please read Note 2(j) to our consolidated financial statements.

2002 Compared to 2001. Our net income decreased $221 million in 2002 compared to 2001 primarily due to decreased revenues resulting from the change from a regulated environment in 2001 to the deregulated ERCOT market ($1.9 billion). Our 2001 revenue was derived based on actual recoverable operating expenses plus an allowed regulatory rate of return based on the rate base while our 2002 revenue was derived from open market sales of capacity and energy at auction and spot market prices. Additionally, fuel and purchased power expenses decreased primarily due to lower natural gas prices and a reduction in overall demand for output from our facilities ($1.4 billion). Operation and maintenance expense decreased primarily due to an absence of major maintenance outages at certain of our plants ($36 million in 2001), which was partially offset by costs related to an early retirement program implemented in 2002 ($12 million), business separation expenses ($7 million) and computer systems necessary for operation in the deregulated market ($6 million). Taxes other than income taxes decreased primarily due to lower tax valuations of generation assets ($20 million). Interest expense decreased $39 million or 60% for the year ended December 31, 2002 from the comparable 2001 period. The decrease was due to the change from the allocation method based on capital structure used to calculate interest expense in 2001 to the allocation of interest in 2002 based on the remaining electric utility debt not specifically identified with CenterPoint Energy's transmission and distribution utility upon deregulation. In connection with the Restructuring and the conveyance of all of CenterPoint Energy's electric generating facilities to us in August 2002, we did not assume any of CenterPoint Energy's long-term debt. The effective tax rates for 2002 and 2001 were 40.3% and 36.5%, respectively. The increase in the effective rate for 2002 compared to 2001 was primarily the result of a reduced benefit from the amortization of investment tax credits, offset by a decrease in state income taxes. Our state tax liability changed from an income-based tax for 2001, to a capital-based tax for 2002, primarily as a result of the 2002 pre-tax loss, which resulted in the reporting of the state tax as a component of the pre-tax loss for 2002 compared to reporting the state tax expense as a component of income tax expense for 2001.

RELATED PARTY TRANSACTIONS

Our Relationships with CenterPoint Energy

Separation Agreement. In connection with the Distribution, we entered into a separation agreement with CenterPoint Energy. This agreement contains provisions governing our relationship with CenterPoint Energy following the Distribution and specifies the related ancillary agreements between us and CenterPoint Energy. In addition, the separation agreement provides for cross-indemnities intended to place sole financial responsibility on us and our subsidiaries for all liabilities associated with the current and historical business and operations we conduct, regardless of the time those liabilities arose, and to place sole financial responsibility for liabilities associated with CenterPoint Energy's other businesses with CenterPoint Energy and its other subsidiaries. The separation agreement also contains indemnification provisions under which we and CenterPoint Energy each indemnify the other with respect to breaches by the indemnifying party of the separation agreement or any ancillary agreements.

Transition Services Agreement. We have entered into a transition services agreement with CenterPoint Energy under which CenterPoint Energy will provide us through the earlier of such time as all services under the agreement are terminated or CenterPoint Energy ceases to own a majority of Texas Genco's common stock, various corporate support services that include accounting, finance, investor relations, planning, legal, communications, governmental and regulatory affairs and human resources, as well as information technology services and other previously shared services such as corporate security, facilities management, accounts receivable, accounts payable and payroll, office support services and purchasing and logistics. These services consist generally of the same types of services as have been provided on an intercompany basis prior to the distribution. The charges we will pay for the services will be on a basis generally intended to allow CenterPoint Energy to recover the fully allocated direct and indirect costs of providing the services, plus all out-of-pocket costs and expenses, but without any profit to CenterPoint Energy, except to the extent routinely included in traditional utility cost of capital.

Tax Allocation Agreement. We are members of the CenterPoint Energy consolidated group for tax purposes, and we will continue to file a consolidated federal income tax return with CenterPoint Energy while CenterPoint Energy retains its 81% interest in us. Accordingly, we have entered into a tax allocation agreement with CenterPoint Energy to govern the allocation of U.S. income tax liabilities and to set forth agreements with respect to certain other tax matters. Generally, if there are tax adjustments related to us which relate to a tax return filed for a period when we were a member of the CenterPoint Energy consolidated group, we are responsible for any increased taxes and we will receive the benefit of any tax refunds.

Employee Benefit Plans. Our eligible employees currently participate in CenterPoint Energy's employee benefit plans and programs in accordance with the terms and conditions of such plans and programs, as may be amended or terminated by CenterPoint Energy at any time. Additionally, CenterPoint Energy expects that a separate pension plan will be established for us in 2005. If this occurs, we will receive an allocation of assets from the CenterPoint Energy pension plan pursuant to rules and regulations under the Employee Retirement Income Security Act of 1974 and record its pension obligations in accordance with SFAS No. 87, "Employer's Accounting for Pensions." It is anticipated that a plan established for us will be under-funded and that such under-funding could be significant. Changes in interest rates and the market values of the securities held by the CenterPoint Energy pension plan during 2004 could materially, positively or negatively, change the funding status of a plan established for us.

Technical Services Agreement with Reliant Resources

Under a technical services agreement, Reliant Resources is obligated to provide engineering and technical support services and environmental, safety and industrial health services to support the operation and maintenance of our facilities. We have notified Reliant Resources that its obligation to provide these services will be terminated effective May 31, 2004. Under the agreement, Reliant Resources is also obligated to provide systems, technical, programming and consulting support services and hardware maintenance (but excluding plant-specific hardware) necessary to provide dispatch planning, dispatch, and settlement and

communication with the ERCOT independent system operator, as well as general information technology services for us. A project is currently underway to identify manpower requirements, evaluate systems alternatives, define costs and develop time lines for replacement of those services considered necessary under the current overall technical services agreement with Reliant Resources. The fees Reliant Resources charges for these services are designed to allow it to recover its fully allocated direct and indirect costs and to obtain reimbursement of all out-of-pocket expenses. Expenses associated with capital investment in systems and software that benefit both the operation of Reliant Resources' facilities and our facilities will be allocated on an installed MW basis.

The overall technical services agreement, while cancelable by us in whole or in part, will terminate in its entirety on the first to occur of:

- CenterPoint Energy's sale of its 81% interest in us, or a sale by us of all or substantially all of our assets; or
- May 31, 2005, provided that we may extend the term of this agreement until December 31, 2005.

South Texas Project Decommissioning Trusts

We are the beneficiary of decommissioning trusts that have been established to provide funding for decontamination and decommissioning of the South Texas Project in which we own a 30.8% interest. CenterPoint Houston collects, through rates or other authorized charges to its electric utility customers, amounts designated for funding the decommissioning trusts, and deposits these amounts into the decommissioning trusts. Upon decommissioning of the facility, in the event funds from the trusts are inadequate, CenterPoint Houston or its successor will be required to collect through rates or other authorized charges to customers as contemplated by the Texas Utilities Code additional amounts required to fund our obligations relating to the decommissioning of the facility. Following the completion of the decommissioning, if surplus funds remain in the decommissioning trusts, the excess will be refunded to the ratepayers of CenterPoint Houston or its successor.

Director Relationships

Our Chairman, David M. McClanahan, is also a director and the chief executive officer of CenterPoint Energy. In addition, two of our directors, Scott E. Rozzell and Gary L. Whitlock, are executive officers of CenterPoint Energy. As a result, these directors may need to recuse themselves and not participate in board meetings where actions are taken in connection with transactions or other relationships involving both companies.

LIQUIDITY AND CAPITAL RESOURCES

Historical Cash Flows

The net cash provided by/used in our operating, investing and financing activities for 2001, 2002 and 2003 is as follows (in millions):

	Year Ended December 31,		
	2001	2002	2003
Cash provided by (used in):			
Operating activities	$ 236	$(140)	$ 387
Investing activities	(409)	(258)	(157)
Financing activities	173	398	(186)

Cash Provided by Operating Activities

Net cash provided by operating activities in 2003 increased $527 million compared to 2002 primarily as a result of higher capacity auction prices, which were driven by higher gas prices. This increase was partially offset by higher income taxes paid of $71 million.

Net cash provided by operating activities in 2002 decreased $376 million compared to 2001. The decrease primarily resulted from lower revenues in the deregulated ERCOT market, increased accounts receivable from the sale of power in the 2002 deregulated electricity market and lower taxes paid of $69 million.

Cash Used in Investing Activities

Net cash used in investing activities decreased $101 million during 2003 compared to 2002 primarily related to a reduction in NOx emissions control expenditures.

Net cash used in investing activities decreased $151 million during 2002 compared to 2001 primarily related to completion of a major portion of the NOx work on our solid fuel units at W.A. Parish in 2001 and the re-scheduling of the NOx installation on our gas units.

Cash Provided by Financing Activities

Cash provided by financing activities decreased $584 million during 2003 compared to 2002 primarily as a result of common stock dividends paid in 2003 and repayments of intercompany borrowings owed to CenterPoint Energy.

Cash provided by financing activities increased $225 million during 2002 compared to 2001 as a result of net transfers from CenterPoint Energy to support our various requirements for working capital and capital expenditures.

Future Sources and Uses of Cash

We expect our liquidity and capital requirements will be affected by our:

- capital requirements related to environmental compliance and other maintenance projects;
- dividend policy;
- debt service requirements; and
- working capital requirements.

On December 31, 2003, we had temporary external investments of $45 million.

In December 2003, Texas Genco, LP, one of our subsidiaries, entered into a 364-day $75 million bank credit facility with a seven-bank syndicate. Proceeds from the revolving credit facility will be used to meet ongoing working capital requirements and for general corporate purposes. Borrowings under the facility may be made at the London interbank offered rate (LIBOR) plus 150 basis points. The facility is secured by a series of first mortgage bonds issued by our wholly owned subsidiary, Texas Genco LP, in an aggregate principal amount of $75 million under a First Mortgage Indenture (the Mortgage) dated December 23, 2003 between JPMorgan Chase Bank, as trustee, and Texas Genco, LP. All of our real and tangible properties, subject to certain exclusions, are currently subject to the lien of the Mortgage. Under the terms of the facility, if CenterPoint Energy ceases to own, directly or indirectly, at least a 50% voting and economic interest in Texas Genco, LP, an event of default will occur and any borrowings thereunder may become immediately due and payable. We believe that our cash flows from operations and our external borrowing capability will be sufficient to meet the operational needs of our business for the next twelve months. As of December 31, 2003, there were no borrowings outstanding under the revolving credit facility.

CenterPoint Energy's $2.3 billion bank facility limits our incurrence of indebtedness for borrowed money to an aggregate principal amount not to exceed $250 million outstanding at any time and requires that proceeds from the sale of any material portion of our assets, proportionate to CenterPoint Energy's ownership

interest in us and subject to certain other requirements, be used to prepay indebtedness under such credit facility. Our new credit facility also limits our incurrence of additional secured indebtedness for borrowed money to a maximum of $175 million aggregate principal amount. Although we are not contractually bound by the limitations in CenterPoint Energy's bank facility , it is expected that CenterPoint Energy would likely cause its representatives on our board of directors to direct our business so as not to breach the terms of its facility.

CenterPoint Energy is a registered holding company under the 1935 Act. In October 2003, the FERC granted exempt wholesale generator status to Texas Genco, LP, our wholly owned subsidiary that owns and operates our electric generating plants. As a result, we are exempt from substantially all provisions of the 1935 Act as long as we remain an exempt wholesale generator.

Capital Requirements. The following table sets forth our capital expenditures requirements for 2003, and estimates of our capital requirements for 2004 through 2008 (in millions).

	2003	2004	2005	2006	2007	2008
Environmental capital requirements	$107	$42	$ 33	$ 43	$ 14	$ —
Other capital requirements	44	52	96	106	88	62
Total capital requirements	$151	$94	$129	$149	$102	$ 62

Contractual Obligations. The following table sets forth estimates of our contractual obligations as of December 31, 2003 to make future payments for 2004 through 2008 and thereafter (in millions):

Contractual Obligations	Total	2004	2005	2006	2007	2008	2009 and thereafter
Fuel commitments	$1,474	$309	$251	$256	$248	$162	$248
Operating lease commitments	99	11	11	10	10	10	47

We have identified retirement obligations for nuclear decommissioning at the South Texas Project and the lignite mine operations which supply our Limestone electric generation facility. We have recorded liabilities as required by SFAS No. 143 of $188 million for the nuclear decommissioning and $6 million for the lignite mine as of December 31, 2003. CenterPoint Houston is required to fund $2.9 million a year to trusts established to fund our share of the decommissioning costs for the South Texas Project. Pursuant to the Texas electric restructuring law, costs associated with nuclear decommissioning that have not been recovered as of January 1, 2002, will continue to be subject to cost-of-service rate regulation and will be included in a charge to CenterPoint Houston's transmission and distribution customers. For additional information on asset retirement obligations and the nuclear decommissioning trusts, please read Notes 2(j) and 8(c) to our consolidated financial statements, respectively.

Revenues derived from our capacity auctions come from two sources: capacity payments and energy payments. Energy payments consist of a variety of charges related to the fuel and ancillary services scheduled through our auctioned capacity entitlements. We bill for these energy payments on a monthly basis in arrears. We expect future collected energy payments will cover all of our future fuel commitments.

Cash Flows From Operations — Reliant Resources as a Significant Customer. To date, we have sold a substantial portion of our auctioned capacity entitlements to subsidiaries of Reliant Resources. Pursuant to a Master Power Purchase and Sale Agreement (as amended) with a subsidiary of Reliant Resources related to power sales in the ERCOT market, we have been granted a security interest in accounts receivable and/or notes associated with the accounts receivable of certain subsidiaries of Reliant Resources to secure up to $250 million in purchase obligations. For more information regarding the impact that Reliant Resources' financial condition may have on our cash flows, please read "Risk Factors" in Item 1 of this report.

Intercompany Borrowings. As a result of our certification by the FERC as an "exempt wholesale generator" under the 1935 Act, CenterPoint Energy has established a second money pool in which we, CenterPoint Energy and certain other unregulated subsidiaries of CenterPoint Energy can participate. Except in an emergency situation (in which CenterPoint Energy could provide funding pursuant to applicable SEC

rules), CenterPoint Energy would be required to obtain approval from the SEC to issue and sell securities for purposes of funding our operations or for CenterPoint Energy to guarantee any of our securities. There is no assurance that CenterPoint Energy will have sufficient funds to meet our cash needs.

Pension Plan. As discussed in Note 6(b) to the consolidated financial statements, we participate in CenterPoint Energy's qualified non-contributory pension plan covering substantially all employees. Pension expense for 2004 is estimated to be $12 million based on an expected return on plan assets of 9.0% and a discount rate of 6.25% as of December 31, 2003. Future changes in plan asset returns, assumed discount rates and various other factors related to the pension will impact our future pension expense and liabilities. We cannot predict with certainty what these factors will be in the future. Additionally, we expect that a separate pension plan will be established for us in 2005. If this occurs, we will receive an allocation of assets from the CenterPoint Energy pension plan pursuant to rules and regulations under the Employee Retirement Income Security Act of 1974 and record our pension obligations in accordance with SFAS No. 87, "Employer's Accounting for Pensions". It is anticipated that a plan established for us will be under-funded and that such under-funding could be significant. Changes in interest rates and the market values of the securities held by the CenterPoint Energy pension plan during 2004 could materially, positively or negatively, change the funding status of a plan established for us.

OFF-BALANCE SHEET FINANCING

Other than operating leases, we have no off-balance sheet financing arrangements.

CRITICAL ACCOUNTING POLICIES

A critical accounting policy is one that is both important to the presentation of our financial condition and results of operations and requires management to make difficult, subjective or complex accounting estimates. An accounting estimate is an approximation made by management of a financial statement element, item or account in the financial statements. Accounting estimates in our historical consolidated financial statements measure the effects of past business transactions or events, or the present status of an asset or liability. The accounting estimates described below require us to make assumptions about matters that are highly uncertain at the time the estimate is made. Additionally, different estimates that we could have used or changes in an accounting estimate that are reasonable likely to occur could have a material impact on the presentation of our financial condition or results of operations. We base our estimates on historical experience and on various other assumptions that we believe are reasonable under the circumstances, the results of which form the basis for making judgments. These estimates may change as new events occur, as more experience is acquired, as additional information is obtained and as our operating environment changes. Our significant accounting policies are discussed in Note 2 to our consolidated financial statements. We believe the following accounting policies involve the application of critical accounting estimates. Accordingly, these accounting estimates have been reviewed and discussed with the audit committee of the board of directors.

Allocation Methodologies Used to Derive Our Financial Statements On a Carve-Out Basis

In 2001, we employed various allocation methodologies to separate the results of operations and financial condition of the generation-related portion of CenterPoint Energy's business from CenterPoint Energy's historical financial statements in order to prepare our financial statements. For 2001, revenues were allocated based on actual costs plus an allowed regulatory rate of return based on regulated invested capital granted to CenterPoint Energy's electric utility by the Texas Utility Commission. The allowed regulatory rate of return was 9.844% for 2001. Expenses, such as fuel, purchased power, operations and maintenance, and depreciation and amortization, and assets, such as property, plant and equipment, and inventory, were specifically identified by function and allocated accordingly for our operations. We used various allocations to disaggregate other common expenses, assets and liabilities between our operations and CenterPoint Energy's regulated transmission and distribution operations. We calculated interest expense based upon an allocation methodology that charged us with financing and equity costs from CenterPoint Energy in proportion to our share of total net assets prior to the effects of deregulation discussed below. These methodologies reflect the impact of

deregulation on our assets and liabilities as of June 30, 1999; however, all existing regulatory assets which are expected to be recovered in the true-up proceeding by our affiliated transmission and distribution utility, CenterPoint Houston, after deregulation have been excluded from these financial statements.

Beginning January 1, 2002, CenterPoint Energy's generation business was segregated from its electric utility as a separate reporting business segment and began selling electricity in the ERCOT market at prices determined by the market. Accordingly, for 2002 and 2003, net income reflects the results of market prices for power. Included in operations for 2002 and 2003 are allocations from CenterPoint Energy for corporate services that included accounting, finance, investor relations, planning, legal, communications, governmental and regulatory affairs and human resources, as well as information technology services and other previously shared services such as corporate security, facilities management, accounts receivable, accounts payable and payroll, office support services and purchasing and logistics.

Management believes the estimates inherent in these allocation methodologies to be reasonable. Had we actually existed as a separate company, our results could have significantly differed from those presented herein. In addition, the historical financial information included in our financial statements is not indicative of our future performance and does not reflect what our financial position and results of operations would have been had we operated as a separate, stand-alone wholesale electric power generation company in a deregulated market during the periods presented.

Impairment of Long-Lived Assets

We review the carrying value of our long-lived assets, including identifiable intangibles, whenever events or changes in circumstances indicate that such carrying values may not be recoverable. Unforeseen events and changes in circumstances and market condition and material differences in the value of long-lived assets and intangibles due to changes in estimates of future cash flows, regulatory matters and operating costs could negatively affect the fair value of our assets and result in an impairment charge.

Fair value is the amount at which the asset could be bought or sold in a current transaction between willing parties and may be estimated using a number of techniques, including quoted market prices or valuations by third parties, present value techniques based on estimates of cash flows, or multiples of earnings or revenue performance measures. The fair value of the asset could be different using different estimates and assumptions in these valuation techniques. Changes in any of these assumptions could result in an impairment charge.

The fair value of our assets could be materially affected by a change in the estimated future cash flows for these assets. We estimate future cash flows using a probability-weighted approach based on the fair value of our common stock, operating projections and estimates of how long we will retain these assets.

NEW ACCOUNTING PRONOUNCEMENTS

See Note 2(j) to the consolidated financial statements for a discussion of new accounting pronouncements that affect us.

Item 7A. *Qualitative and Quantitative Disclosures About Market Risk.*

Interest Rate Risk

As discussed in Note 8(c) to our consolidated financial statements, CenterPoint Houston contributed $14.8 million in 2001 to trusts established to fund our share of the decommissioning costs for the South Texas Project. In 2002 and 2003, CenterPoint Houston contributed $2.9 million to these trusts. The securities held by the trusts for decommissioning costs had an estimated fair value of $189 million as of December 31, 2003, of which approximately 37% were debt securities that subject us to risk of loss of fair value with movements in market interest rates. If interest rates were to increase by 10% from their levels at December 31, 2003, the decrease in fair value of the debt securities would be approximately $1 million.

Equity Market Value Risk

As discussed above under "— Interest Rate Risk," CenterPoint Houston contributes to trusts established to fund our share of the decommissioning costs for the South Texas Project, which held debt and equity securities as of December 31, 2003. The equity securities expose us to losses in fair value. If the market prices of the individual equity securities were to decrease by 10% from their levels at December 31, 2003, the resulting loss in fair value of these securities would be approximately $12 million. Currently, the risk of an economic loss is mitigated as discussed above under "— Interest Rate Risk."

Commodity Price Risk

Our gross margins are dependent upon the market price for power in the ERCOT market. Our gross margins are primarily derived from the sale of capacity entitlements associated with our large, solid fuel base-load generating units, including our Limestone and W.A. Parish facilities and our interest in the South Texas Project. The gross margins generated from payments associated with the capacity of these units are directly impacted by natural gas prices. Since the fuel costs for our base-load units are largely fixed under long-term contracts, they are generally not subject to significant daily and monthly fluctuations. However, the market price for power in the ERCOT market is directly affected by the price of natural gas. Because natural gas is the marginal fuel of facilities serving the ERCOT market during most hours, its price has a significant influence on the price of electric power. As a result, the price customers are willing to pay for entitlements to our solid fuel base-load capacity generally rises and falls with natural gas prices.

Item 8. *Financial Statements and Supplementary Data of the Company.*

TEXAS GENCO HOLDINGS, INC.

STATEMENTS OF CONSOLIDATED OPERATIONS
(Thousands of Dollars)

	Year Ended December 31,		
	2001	2002	2003
Revenues:			
Revenues	$3,410,945	$ —	$ —
Energy revenues	—	1,093,714	1,221,348
Capacity and other revenues	—	447,261	781,020
Total	3,410,945	1,540,975	2,002,368
Expenses:			
Fuel costs	1,303,981	989,560	1,098,269
Purchased power	1,222,552	93,841	72,509
Operation and maintenance	401,677	391,465	411,940
Depreciation and amortization	154,248	156,740	159,010
Taxes other than income taxes	63,378	42,930	38,681
Total	3,145,836	1,674,536	1,780,409
Operating Income (Loss)	265,109	(133,561)	221,959
Other Income	2,100	3,423	2,176
Interest Expense	(65,017)	(25,637)	(1,583)
Income (Loss) Before Income Taxes and Cumulative Effect of Accounting Change	202,192	(155,775)	222,552
Income Tax Benefit (Expense)	(73,804)	62,832	(71,286)
Income (Loss) Before Cumulative Effect of Accounting Change	128,388	(92,943)	151,266
Cumulative Effect of Accounting Change, net of tax	—	—	98,910
Net Income (Loss)	$ 128,388	$ (92,943)	$ 250,176
Basic and Diluted Earnings Per Share:			
Income (Loss) Before Cumulative Effect of Accounting Change	$ 1.60	$ (1.16)	$ 1.89
Cumulative Effect of Accounting Change, net of tax	—	—	1.24
Net Income (Loss)	$ 1.60	$ (1.16)	$ 3.13

See Notes to the Company's Consolidated Financial Statements

TEXAS GENCO HOLDINGS, INC.

CONSOLIDATED BALANCE SHEETS
(Thousands of Dollars)

	December 31, 2002	December 31, 2003
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 578	$ 44,558
Customer accounts receivable	68,604	78,122
Accounts receivable, other	4,544	3,716
Inventory	156,167	169,692
Taxes receivable	4,368	—
Prepayments and other current assets	4,024	2,304
Total current assets	238,285	298,392
Property, Plant and Equipment, net	4,095,637	4,125,595
Other Assets:		
Nuclear decommissioning trust	162,576	189,182
Other	11,584	26,462
Total other assets	174,160	215,644
Total Assets	$4,508,082	$4,639,631
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable, affiliated companies, net	$ 22,654	$ 7,802
Accounts payable, fuel	76,399	68,747
Accounts payable, other	43,877	40,165
Notes payable, affiliated companies, net	86,184	—
Taxes and interest accrued	42,959	107,605
Deferred capacity auction revenue	48,721	86,853
Other	15,918	17,579
Total current liabilities	336,712	328,751
Other Liabilities:		
Accumulated deferred income taxes, net	813,246	844,545
Unamortized investment tax credit	170,569	150,533
Nuclear decommissioning reserve	139,664	187,997
Benefit obligations	15,751	18,399
Accrued mine reclamation costs	39,765	6,000
Notes payable, affiliated companies, net	18,995	—
Other	149,337	70,245
Total other liabilities	1,347,327	1,277,719
Commitments and Contingencies (Note 8)		
Shareholders' Equity	2,824,043	3,033,161
Total Liabilities and Shareholders' Equity	$4,508,082	$4,639,631

See Notes to the Company's Consolidated Financial Statements

TEXAS GENCO HOLDINGS, INC.

STATEMENTS OF CONSOLIDATED CASH FLOWS
(Thousands of Dollars)

	Year Ended December 31,		
	2001	2002	2003
Cash Flows from Operating Activities:			
Net income (loss)	$ 128,388	$ (92,943)	$ 250,176
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Depreciation and amortization	154,248	156,740	159,010
Fuel-related amortization	16,740	25,113	23,385
Deferred income taxes	(29,194)	(27,161)	8,693
Investment tax credit	(13,106)	(12,144)	(10,876)
Cumulative effect of accounting change	—	—	(98,910)
Changes in other assets and liabilities:			
Accounts receivable	(19,554)	(34,975)	(8,690)
Inventory	(16,483)	24,082	(13,525)
Taxes receivable	—	(4,368)	4,368
Accounts payable	(95,490)	(75,659)	(11,364)
Accounts payable, affiliate	19,743	(25,772)	(14,852)
Taxes and interest accrued	60,608	(79,728)	64,646
Accrued reclamation costs	8,505	11,334	5,907
Benefit obligations	2,453	(17,423)	2,648
Deferred revenue from capacity auctions	—	48,721	38,132
Other current assets	(491)	(1,016)	1,720
Other current liabilities	(665)	1,257	1,661
Other long-term assets	(5,822)	15,757	678
Other long-term liabilities	26,209	(51,756)	(15,866)
Net cash provided by (used in) operating activities	236,089	(139,941)	386,941
Cash Flows from Investing Activities:			
Capital expenditures and other	(409,002)	(257,630)	(156,963)
Net cash used in investing activities	(409,002)	(257,630)	(156,963)
Cash Flows from Financing Activities:			
Payment of common stock dividends	—	—	(80,000)
Net change in capitalization activity	172,913	292,970	—
Increase (decrease) in short-term notes payables, affiliate	—	86,184	(86,184)
Increase (decrease) in long-term notes payable, affiliate	—	18,995	(18,995)
Debt issuance costs	—	—	(819)
Net cash provided by (used in) financing activities	172,913	398,149	(185,998)
Net Increase in Cash and Cash Equivalents	—	578	43,980
Cash and Cash Equivalents at Beginning of Period	—	—	578
Cash and Cash Equivalents at End of Period	$ —	$ 578	$ 44,558
Supplemental Disclosure of Cash Flow Information:			
Cash Payments:			
Interest	$ 64,267	$ 4,270	$ 8,506
Income taxes (refunds)	60,963	(7,749)	63,623

See Notes to the Company's Consolidated Financial Statements

TEXAS GENCO HOLDINGS, INC.

STATEMENTS OF CONSOLIDATED CAPITALIZATION AND SHAREHOLDERS' EQUITY
(Thousands of Dollars)

	Capital Stock	Additional Paid-In Capital	Retained Earnings (Deficit)	Total Shareholders' Equity	Capitalization	Total Capitalization and Shareholders' Equity
Balance as of December 31, 2000	$—	$ —	$ —	$ —	$2,322,715	$2,322,715
Net income(1)	—	—	—	—	128,388	128,388
Net transfers from parent	—	—	—	—	172,913	172,913
Balance as of December 31, 2001	—	—	—	—	2,624,016	2,624,016
Net loss(2)	—	—	(54,460)	(54,460)	(38,483)	(92,943)
Net transfers from parent	1	2,878,502	—	2,878,503	(2,585,533)	292,970
Balance as of December 31, 2002	1	2,878,502	(54,460)	2,824,043	—	2,824,043
Net income(2)	—	—	250,176	250,176	—	250,176
Common stock dividends — $1.00 per share	—	—	(80,000)	(80,000)	—	(80,000)
Net transfers from parent	—	38,942	—	38,942	—	38,942
Balance as of December 31, 2003	$ 1	$2,917,444	$115,716	$3,033,161	$ —	$3,033,161

(1) Net income included in Capitalization for 2001 reflects the net income derived from the allocation of revenue, operating expenses, other income, interest expense and income tax expense from the rate regulated electric utility of Reliant Energy, Incorporated, (Reliant Energy) the predecessor of CenterPoint Energy Houston Electric, LLC (CenterPoint Houston), which was comprised of transmission and distribution, generation and retail components. For further discussion related to the basis of presentation, See Note 1.

(2) Beginning January 1, 2002, Reliant Energy's electric generation business was segregated in an unincorporated division from its other electric utility operations as a separate reporting business segment. In June 1999, the Texas legislature enacted a law that substantially amended the regulatory structure governing electric utilities in Texas in order to encourage retail electric competition (the Texas electric restructuring law). Under the Texas electric restructuring law, the Company and other power generators in Texas ceased to be subject to traditional cost-based regulation on January 1, 2002. Since that date, the Company has been selling generation capacity, energy and ancillary services to wholesale purchasers at prices determined by the market. Accordingly, for 2002, net loss reflects revenue received from market-based power sales. Retained deficit at December 31, 2002 reflects the Company's net loss since August 31, 2002, the date of the restructuring as discussed in Note 1. The Company's net loss prior to the restructuring is reflected as a component of capitalization.

See Notes to the Company's Consolidated Financial Statements

(1) Background and Basis of Presentation

Background. In June 1999, the Texas legislature enacted an electric restructuring law which substantially amended the regulatory structure governing electric utilities in Texas in order to encourage retail electric competition. In December 2001, the shareholders of Reliant Energy, Incorporated (Reliant Energy) approved a restructuring proposal that was submitted in response to the Texas electric restructuring law and pursuant to which Reliant Energy would, among other things, (1) convey its Texas electric generation assets to an affiliated company, (2) become an indirect, wholly owned subsidiary of a new public utility holding company, CenterPoint Energy, Inc. (CenterPoint Energy), (3) be converted into a Texas limited liability company named CenterPoint Energy Houston Electric, LLC (CenterPoint Houston) and (4) distribute the capital stock of its operating subsidiaries to CenterPoint Energy. Texas Genco Holdings, Inc. (Texas Genco or the Company) represents the portfolio of generating facilities owned during the periods presented by these financial statements by the unincorporated electric utility division of Reliant Energy.

On August 24, 2001, Reliant Energy incorporated Texas Genco, a Texas corporation, as a wholly owned subsidiary. In February 2002, the Company issued 1,000 shares of its $1.00 par value common stock to Reliant Energy in exchange for $1,000. In February 2002, Reliant Energy made a capital contribution of $3,000 to the Company. During the period ended June 30, 2002, Reliant Energy made a capital contribution of $14,000 to the Company for payment of general and administrative expenses associated with maintaining its corporate structure. The Company did not conduct any activities other than those mentioned above through August 31, 2002.

Effective August 31, 2002, Reliant Energy completed the restructuring described above. As a result, on that date Reliant Energy conveyed all of its electric generating facilities to the Company, which was accounted for as a business combination of entities under common control. The Company subsequently became an indirect wholly owned subsidiary of CenterPoint Energy. CenterPoint Energy is subject to regulation by the Securities and Exchange Commission as a "registered holding company" under the Public Utility Holding Company Act of 1935, as amended (1935 Act). As used herein, CenterPoint Energy also refers to the former Reliant Energy for dates prior to the restructuring. In October 2003, the Federal Energy Regulatory Commission (FERC) granted exempt wholesale generator status to Texas Genco, LP, the Company's wholly owned subsidiary that owns and operates its electric generating plants. As a result, the Company is exempt from substantially all provisions of the 1935 Act as long as it remains an exempt wholesale generator.

As of January 1, 2002, CenterPoint Energy's electric utility unbundled its businesses in order to separate its power generation, transmission and distribution, and retail electric businesses into separate units. Under the Texas electric restructuring law, as of January 1, 2002, the Company ceased to be subject to traditional cost-based regulation. Since that date, the Company has been selling generation capacity, energy and ancillary services to wholesale purchasers at prices determined by the market. To facilitate a competitive market, each power generation company affiliated with a transmission and distribution utility is required to sell at auction firm entitlements to 15% of the output of its installed generating capacity on a forward basis for varying terms of up to two years (state-mandated auctions). The Company's first state-mandated auction was held in September 2001 for power delivered beginning January 1, 2002. This obligation continues until January 1, 2007 unless before that date the Public Utility Commission of Texas (Texas Utility Commission) determines that at least 40% of the quantity of electric power consumed in 2000 by residential and small commercial customers in CenterPoint Houston's service area is being served by retail electric providers not affiliated with CenterPoint Energy. Reliant Resources, Inc. (Reliant Resources) is deemed to be an affiliate of CenterPoint Energy for purposes of this test.

Basis of Presentation. The consolidated financial statements include the operations of Texas Genco Holdings, Inc. and its subsidiaries, which manage and operate the Company's electric generation operations. The consolidated financial statements of the Company are presented on a carve-out basis, and present the historical financial position, results of operations and net cash flows of the historically regulated generation-

related business of CenterPoint Energy, and are not indicative of the financial position, results of operations or net cash flows that would have existed had the Company been an independent company operating in the Texas deregulated electricity market (ERCOT market) for the year ended December 31, 2001. Beginning January 1, 2002, CenterPoint Energy's generation business was segregated from CenterPoint Energy's electric utility as a separate reporting business segment and began selling electricity in the ERCOT market at prices determined by the market. Accordingly, for 2002 and 2003, net income (loss) reflects the results of market prices for power. Included in operations for 2002 and 2003 are allocations from CenterPoint Energy for corporate services that included accounting, finance, investor relations, planning, legal, communications, governmental and regulatory affairs and human resources, as well as information technology services and other previously shared services such as corporate security, facilities management, accounts receivable, accounts payable and payroll, office support services and purchasing and logistics.

Certain information in these consolidated financial statements as of December 31, 2002 and for each of the years in the two-year period ended December 31, 2002 relating to the results of operations and financial condition was derived from the historical financial statements of CenterPoint Energy which have been prepared in accordance with accounting principles generally accepted in the United States of America (GAAP). Various allocation methodologies were employed during these periods to separate the results of operations and financial condition of the generation-related portion of CenterPoint Energy's business from CenterPoint Energy's historical financial statements. For 2001, revenues were allocated based on the allowed regulatory rate of return on regulated invested capital granted to CenterPoint Energy's electric utility by the Texas Utility Commission. The allowed regulatory rate of return was 9.844% for 2001. Expenses during 2001, such as fuel, purchased power, operations and maintenance and depreciation and amortization, and assets, such as property, plant and equipment and inventory, were specifically identified by function and allocated accordingly for the Company's operations. Various allocations were used to disaggregate other common expenses, assets and liabilities between the Company and CenterPoint Energy's regulated transmission and distribution operations as of December 31, 2001 and for the two-year period then ended. Interest expense was calculated based upon an allocation methodology that charged the Company with financing and equity costs from CenterPoint Energy in proportion to its share of total net assets. Interest expense in 2002 through August 31, 2002 was allocated based upon the remaining electric utility debt not specifically identified with Reliant Energy's transmission and distribution utility upon deregulation. Effective with the restructuring of Reliant Energy, no long-term debt was assumed by the Company and interest is incurred on borrowings from CenterPoint Energy. These methodologies reflect the impact of deregulation on the Company's assets and liabilities as of June 30, 1999; however, all existing regulatory assets which are expected to be recovered by the transmission and distribution utility after deregulation have been excluded from these consolidated financial statements.

Management believes these allocation methodologies to be reasonable. Had the Company actually existed as a separate company, its results could have significantly differed from those presented herein. In addition, future results of operations, financial position and net cash flows are expected to materially differ from the historical results presented.

On January 6, 2003, CenterPoint Energy distributed approximately 19% of the 80 million shares of Texas Genco's common stock that were then outstanding to CenterPoint Energy's shareholders. Earnings per share has been presented as if the 80 million shares were outstanding for all historical periods in accordance with Statement of Financial Accounting Standards (SFAS) No. 128, "Earnings Per Share."

(2) Summary of Significant Accounting Policies

(a) Reclassifications and Use of Estimates

Certain amounts from the previous years have been reclassified to conform to the 2003 presentation of financial statements. These reclassifications do not affect net income.

The process of preparing financial statements in conformity with GAAP requires the use of estimates and assumptions regarding certain types of assets, liabilities, revenues and expenses. Also, such estimates relate to unsettled transactions and events as of the date of the financial statements. Accordingly, upon settlement, actual results may differ from estimated amounts. In addition to these estimates, see Note 1 (Background and Basis of Presentation) for a discussion of the estimates used and methodologies employed to derive the Company's historical financial statements.

(b) Inventory

Inventory consists principally of materials and supplies, coal and lignite, natural gas and fuel oil. Inventories used in the production of electricity are valued at the lower of average cost or market except for coal and lignite, which are valued under the last-in, first-out method. Below is a detail of inventory:

	December 31,	
	2002	2003
	(In thousands)	
Materials and supplies	$ 92,869	$ 92,409
Coal and lignite	42,791	49,835
Natural gas	16,733	21,340
Fuel oil	3,774	6,108
Total inventory	$156,167	$169,692

(c) Property, Plant and Equipment

Property, plant and equipment are recorded at historical cost. Repair and maintenance costs are charged to the appropriate expense accounts as incurred. Property, plant and equipment includes the following:

	Estimated Useful Lives (Years)	December 31,	
		2002	2003
		(In thousands)	
Gas-fired generation facilities	30-60	$ 2,274,317	$ 2,277,591
Coal and lignite-fired generation facilities	50	3,820,208	3,934,683
Nuclear generation facilities	40	2,561,239	2,635,999
Nuclear fuel		344,003	356,037
Other	5-50	610,573	630,594
Total		9,610,340	9,834,904
Accumulated depreciation and amortization		(5,514,703)	(5,709,309)
Property, plant and equipment, net		$ 4,095,637	$ 4,125,595

Prior to the restructuring described in Note 1 (Background and Basis of Presentation), substantially all of the Company's physical assets used in the conduct of the business and operations of electric generation were subject to liens securing CenterPoint Energy's First Mortgage Bonds. In connection with the restructuring, these assets were released from the liens. All of the Company's real and tangible properties, subject to certain exclusions, are currently subject to the lien of a First Mortgage Indenture (the Mortgage) dated December 23, 2003 between JPMorgan Chase Bank, as trustee, and the Company's wholly owned subsidiary, Texas Genco, LP. As of December 31, 2003, Texas Genco, LP had issued $75 million aggregate principal amount of first mortgage bonds under the Mortgage to secure obligations under the Company's $75 million 364-day revolving credit facility. (See Note 3).

For further information regarding removal costs previously recorded as a component of accumulated depreciation, see Note 2(j).

(d) Depreciation and Amortization

Depreciation is computed using the straight-line method based on economic lives. Depreciation and amortization expense for 2001, 2002 and 2003 was $154 million, $157 million and $159 million, respectively.

(e) Capitalized Interest

Capitalized interest is reflected as a reduction to interest expense in the Statements of Consolidated Operations. During the years ended December 31, 2001, 2002 and 2003, the Company capitalized interest of $4 million, $7 million and $9 million, respectively.

(f) Long-lived Assets and Intangibles

The Company periodically evaluates long-lived assets when events or changes in circumstances indicate that the carrying value of these assets may not be recoverable. The determination of whether an impairment has occurred is based on an estimate of undiscounted cash flows attributable to the assets, as compared to the carrying value of the assets. An impairment analysis of generating facilities requires estimates of possible future market prices, load growth, competition and many other factors over the lives of the facilities. A resulting impairment loss is highly dependent on these underlying assumptions. No impairment has been recorded in any of the three years in the period ended December 31, 2003.

(g) Revenue Recognition

Prior to January 1, 2002, revenues were derived based on actual costs plus an allowed regulatory rate of return based on regulated invested capital. For the periods subsequent to January 1, 2002, the Company has been accounted for as a separate business segment of CenterPoint Energy selling electricity to wholesale purchasers in the ERCOT market. Accordingly, revenues represent actual results of CenterPoint Energy's generation business segment in 2002 operating in a deregulated market. Beginning January 1, 2002, the Company has two primary components of revenue: (1) capacity payments, which entitles the owner to power, and (2) energy payments, which are intended to cover the costs of fuel for the actual electricity produced. Capacity payments are billed and collected one month prior to actual energy deliveries and are recorded as deferred revenue until the month of actual energy delivery. At that point, the deferred revenue is reversed, and both capacity and energy payment revenues are recognized. Prior to 2002, all purchased power was part of the total load used to serve retail customers of the integrated utility. Beginning in 2002, fuel costs and purchased power are costs incurred to support sales of energy in the state-mandated auctions and contractually-mandated auctions required by the Texas Utility Commission, and the corresponding revenues are recorded as energy revenues.

(h) Income Taxes

The Company is included in the consolidated income tax returns of CenterPoint Energy. The Company calculates its income tax provision on a separate return basis under a tax sharing agreement with CenterPoint Energy. The Company uses the liability method of accounting for deferred income taxes and measures deferred income taxes for all significant income tax temporary differences. Investment tax credits were deferred and are being amortized over the estimated lives of the related property. Current federal and state income taxes payable are payable to or receivable from CenterPoint Energy.

(i) Statement of Consolidated Cash Flows

For purposes of reporting cash flows, the Company considers cash equivalents to be short-term, highly liquid investments readily convertible to cash.

(j) New Accounting Pronouncements

Effective January 1, 2003, the Company adopted SFAS No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143). SFAS No. 143 requires the fair value of an asset retirement obligation to be recognized as a liability is incurred and capitalized as part of the cost of the related tangible long-lived assets. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Retirement obligations associated with long-lived assets included within the scope of SFAS No. 143 are those for which a legal obligation exists under enacted laws, statutes and written or oral contracts, including obligations arising under the doctrine of promissory estoppel.

The Company has identified retirement obligations for nuclear decommissioning at the South Texas Project Electric Generating Station (South Texas Project) and for lignite mine operations which supply the Limestone electric generation facility. Prior to adoption of SFAS No. 143, the Company had recorded liabilities for nuclear decommissioning and the reclamation of the lignite mine. Liabilities were recorded for estimated decommissioning obligations of $140 million and $40 million for reclamation of the lignite at December 31, 2002. Upon adoption of SFAS No. 143 on January 1, 2003, the Company reversed the $140 million previously accrued for the nuclear decommissioning of the South Texas Project and recorded a plant asset of $99 million offset by accumulated depreciation of $36 million as well as a retirement obligation of $187 million. The $16 million difference between amounts previously recorded and the amounts recorded upon adoption of SFAS No. 143 is being deferred as a liability as the recovery of nuclear decommissioning costs continues to be regulated by the Texas Utility Commission. Accordingly, any difference between assets and liabilities associated with nuclear decommissioning are recorded as a receivable or liability as such amount will be funded by or returned to customers of CenterPoint Houston or its successor. The Company also reversed the $40 million it had previously recorded for the mine reclamation and recorded a plant asset of $1 million as well as a retirement obligation of $4 million. The $37 million difference between amounts previously recorded and the amounts recorded upon adoption of SFAS No. 143 was recorded as a cumulative effect of accounting change. The Company has also identified other asset retirement obligations that cannot be estimated because the assets associated with the retirement obligations have an indeterminate life.

The following represents the balances of the asset retirement obligation as of January 1, 2003 and the additions and accretion of the asset retirement obligation for the year ended December 31, 2003:

	Balance, January 1, 2003	Liabilities Incurred	Liabilities Settled	Accretion	Cash Flow Revisions	Balance, December 31, 2003
			(In millions)			
Nuclear decommissioning	$187	—	—	$1	—	$188
Lignite mine	4	—	—	2	—	6
	$191	—	—	$3	—	$194

The following represents the pro-forma effect on the Company's net income for the year ended December 31, 2002, as if the Company had adopted SFAS No. 143 as of January 1, 2002 (in millions, except per share amounts):

	Year Ended December 31, 2002
Net loss as reported	$ (93)
Pro-forma net loss	(86)
Diluted earnings per share:	
Net loss as reported	$(1.16)
Pro-forma net loss	(1.07)

The following represents the Company's asset retirement obligations on a pro-forma basis as if it had adopted SFAS No. 143 as of December 31, 2002:

	As Reported	Pro-forma
	(In millions)	
Nuclear decommissioning	$140	$187
Lignite mine	40	4
Total	$180	$191

The Company has previously recognized removal costs as a component of depreciation expense. As of December 31, 2002, these removal costs of $115 million have been reclassified from accumulated depreciation to other long-term liabilities in the Consolidated Balance Sheet. Upon adoption of SFAS No. 143, the Company reversed $115 million of previously recognized removal costs as a cumulative effect of accounting change. The total cumulative effect recognized upon adoption of SFAS No. 143 was $99 million after-tax ($152 million pre-tax).

On December 23, 2003, the FASB issued SFAS No. 132 (Revised 2003), "Employer's Disclosures about Pensions and Other Postretirement Benefits" (SFAS No. 132(R)). This standard increases the existing disclosure requirements by requiring more details about pension plan assets, benefit obligations, cash flows, benefit costs and related information. Companies will be required to segregate plan assets by category, such as debt, equity and real estate, and to provide certain expected rates of return and other informational disclosures. SFAS No. 132(R) also requires companies to disclose various elements of pension and postretirement benefit costs in interim-period financial statements for quarters beginning after December 15, 2003. The Company has adopted the disclosure requirements of SFAS No. 132(R) in Note 6 to these consolidated financial statements.

In December 2003, Congress passed the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act) which will become effective in 2006. The Act contains incentives for the Company, if it continues to provide prescription drug benefits for its retirees, through the provision of a non-taxable reimbursement to the Company of specified costs. The Company has many different alternatives available under the Act, and, until clarifying regulations are issued with respect to the Act, the Company is unable to determine the financial impact. On January 12, 2004, the FASB issued FASB Staff Position (FSP) FAS 106-1, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (FAS 106-1)." In accordance with FSP FAS 106-1, the Company's postretirement benefits obligations and net periodic postretirement benefit cost in the financial statements and accompanying notes do not reflect the effects of the legislation. Specific authoritative guidance on the accounting for the legislation is pending and that guidance, when issued, may require the Company to change previously reported information.

(3) Short-Term Borrowings

In December 2003, Texas Genco, LP, a subsidiary of the Company, entered into a 364-day $75 million bank credit facility with a seven-bank syndicate. As of December 31, 2003, there were no borrowings outstanding under the revolving credit facility. Proceeds from the revolving credit facility will be used to meet ongoing working capital requirements and for general corporate purposes. Borrowings under the facility may be made at the London interbank offered rate (LIBOR) plus 150 basis points. The facility is secured by a series of first mortgage bonds issued by Texas Genco LP, in an aggregate principal amount of $75 million under a First Mortgage Indenture (the Mortgage) dated December 23, 2003 between JPMorgan Chase Bank, as trustee, and Texas Genco, LP. All of the Company's real and tangible properties, subject to certain exclusions, are currently subject to the lien of the Mortgage. Under the terms of the facility, if CenterPoint Energy ceases to own, directly or indirectly, at least a 50% voting and economic interest in Texas Genco, LP, an event of default will occur and any borrowings thereunder may become immediately due and payable. Texas Genco's revolving credit facility contains various business and financial covenants. Texas Genco is currently in compliance with the covenants under the credit agreement.

(4) Related Party Transactions and Major Customers

As of December 31, 2002, the Company had $86 million in short-term borrowings and $19 million in long-term borrowings from CenterPoint Energy and its subsidiaries. Such borrowings were used for working capital purposes. Interest expense associated with the borrowings for 2002 was $7 million. As of December 31, 2003, the Company had no short-term or long-term borrowings from CenterPoint Energy and its subsidiaries. As of December 31, 2002, the weighted average interest rate on the borrowings was 6.2%. In addition, through August 31, 2002, $25 million of interest expense was allocated to the Company related to the remaining electric utility debt not specifically identified with CenterPoint Energy's transmission and distribution utility upon deregulation. Interest expense associated with the borrowings during 2003 was $7 million.

As of December 31, 2002, the Company had net accounts payable to affiliates of $23 million. As of December 31, 2003, the Company had net accounts payable to affiliates of $8 million.

During 2002 and 2003, the sales and services by the Company to Reliant Resources and its subsidiaries totaled $1 billion and $1.4 billion, respectively. During 2002 and 2003, sales and services by the Company to CenterPoint Energy and its affiliates totaled $53 million and $-0-, respectively.

During 2002 and 2003, the sales and services by the Company to a major customer other than Reliant Resources totaled $226 million and $205 million, respectively.

During 2002 and 2003, purchases of natural gas by the Company from CenterPoint Energy and its affiliates were $41 million and $29 million, respectively.

CenterPoint Energy provides some corporate services to the Company. The costs of services have been directly charged to the Company using methods that management believes are reasonable. These methods include negotiated usage rates, dedicated asset assignment, and proportionate corporate formulas based on assets, operating expenses and employees. These charges are not necessarily indicative of what would have been incurred had the Company not been an affiliate. Amounts charged to the Company for these services were $47 million for 2002 and $32 million in 2003 and are included primarily in operation and maintenance expenses.

Separation Agreement. In connection with the distribution by CenterPoint Energy to its shareholders of 19% of the Company's outstanding common stock, the Company entered into a separation agreement with CenterPoint Energy. This agreement contains provisions governing the Company's relationship with CenterPoint Energy following the distribution and specifies the related ancillary agreements between the Company and CenterPoint Energy. In addition, the separation agreement provides for cross-indemnities

intended to place sole financial responsibility on the Company and its subsidiaries for all liabilities associated with the current and historical business and operations the Company conducts, regardless of the time those liabilities arose, and to place sole financial responsibility for liabilities associated with CenterPoint Energy's other businesses with CenterPoint Energy and its other subsidiaries. The separation agreement also contains indemnification provisions under which the Company and CenterPoint Energy each indemnify the other with respect to breaches by the indemnifying party of the separation agreement or any ancillary agreements.

Tax Allocation Agreement. The Company is a member of the CenterPoint Energy consolidated group for tax purposes, and the Company will continue to file a consolidated federal income tax return with CenterPoint Energy while CenterPoint Energy retains its 81% interest in the Company. Accordingly, the Company has entered into a tax allocation agreement with CenterPoint Energy to govern the allocation of U.S. income tax liabilities and to set forth agreements with respect to certain other tax matters. Generally, if there are tax adjustments related to the Company which relate to a tax return filed for a period when the Company was a member of the CenterPoint Energy consolidated group, the Company is responsible for any increased taxes and the Company will receive the benefit of any tax refunds.

(5) Jointly Owned Electric Utility Plant

The Company owns a 30.8% interest in the South Texas Project, which consists of two 1,250 MW nuclear generating units, and bears a corresponding 30.8% share of capital and operating costs associated with the project. The South Texas Project is owned as a tenancy in common among the Company and three other co-owners, with each owner retaining its undivided ownership interest in the two nuclear-fueled generating units and the electrical output from those units. The Company is severally liable, but not jointly liable, for the expenses and liabilities of the South Texas Project. CenterPoint Energy and the other three co-owners organized STP Nuclear Operating Company (STPNOC) to operate and maintain the South Texas Project. STPNOC is managed by a board of directors comprised of one director appointed by each of the four owners, along with the chief executive officer of STPNOC. The Company's share of direct expenses of the South Texas Project is included in the corresponding operating expense categories in the accompanying financial statements. As of December 31, 2002 and 2003, Texas Genco's total utility plant for the South Texas Project was $385 million and $431 million, respectively, (net of $2.2 billion accumulated depreciation which includes an impairment loss recorded in 1999 of $745 million). As of December 31, 2002 and 2003, Texas Genco's investment in nuclear fuel was $42 million (net of $302 million amortization) and $40 million (net of $316 million amortization), respectively.

(6) Employee Benefit Plans

(a) Incentive Compensation Plans

During 2003, the Company established a long-term incentive compensation plan (LICP) that provides cash-based performance units to key employees of the Company. The Company's compensation cost related to this plan was less than $1 million for 2003.

(b) Pension

Substantially all of the Company's employees participate in CenterPoint Energy's qualified non-contributory pension plan. The benefit accrual is in the form of a cash balance of a specified percentage of annual pay plus accrued interest. CenterPoint Energy's funding policy is to review amounts annually in accordance with applicable regulations in order to achieve adequate funding of projected benefit obligations. Pension expense is allocated to the Company based on covered employees. Assets of the plan are not segregated or restricted by CenterPoint Energy's participating subsidiaries and accrued obligations for the Company employees would be the obligation of the retirement plan if the Company were to withdraw. Pension benefit was $1 million for the year ended December 31, 2001. The Company recognized pension expense of

$15 million (including $9 million of non-recurring early retirement expenses) and $17 million for the years ended December 31, 2002 and 2003, respectively.

In addition to the plan, the Company participates in CenterPoint Energy's non-qualified pension plan, which allows participants to retain the benefits to which they would have been entitled under the non-contributory pension plan except for federally mandated limits on these benefits or on the level of salary on which these benefits may be calculated. The expense associated with the non-qualified pension plan was less than $1 million in 2001, 2002 and 2003.

(c) Savings Plan

The Company participates in CenterPoint Energy's qualified savings plan, which includes a cash or deferred arrangement under Section 401(k) of the Internal Revenue Code of 1986, as amended. Under the plan, participating employees may contribute a portion of their compensation, on a pre-tax or after-tax basis, generally up to a maximum of 16% of compensation. CenterPoint Energy matches 75% of the first 6% of each employee's compensation contributed. CenterPoint Energy may contribute an additional discretionary match of up to 50% of the first 6% of each employee's compensation contributed. These matching contributions are fully vested at all times. A substantial portion of the matching contribution is initially invested in CenterPoint Energy common stock. CenterPoint Energy allocates to the Company the savings plan benefit expense related to the Company's employees.

Savings plan benefit expense was $6 million, $9 million and $7 million for the years ended December 31, 2001, 2002 and 2003, respectively.

(d) Postretirement Benefits

The Company's employees participate in CenterPoint Energy's plan which provides certain healthcare and life insurance benefits for retired employees on a contributory and non-contributory basis. Employees become eligible for these benefits if they have met certain age and service requirements at retirement, as defined in the plans. Under plan amendments effective in early 1999, healthcare benefits for future retirees were changed to limit employer contributions for medical coverage. Such benefit costs are accrued over the active service period of employees. The Company funds all of its obligations on a pay-as-you-go basis.

On January 12, 2004, the FASB issued FAS 106-1. In accordance with FSP FAS 106-1, the Company's postretirement benefits obligations and net periodic postretirement benefit cost in the financial statements and accompanying notes do not reflect the effects of the legislation. Specific authoritative guidance on the accounting for the legislation is pending and that guidance, when issued, may require the Company to change previously reported information.

The net postretirement benefit cost includes the following components:

	Year Ended December 31,		
	2001	2002	2003
	(In millions)		
Service cost — benefits earned during the period	$ 1	$ 1	$ 1
Interest cost on projected benefit obligation	6	3	3
Expected return on plan assets	(4)	(1)	(2)
Net amortization	4	1	2
Benefit enhancement	—	3	—
Net postretirement benefit cost	$ 7	$ 7	$ 4

The Company used the following assumptions to determine net postretirement benefit costs:

	Year Ended December 31,		
	2001	2002	2003
Discount rate	7.50%	7.25%	6.75%
Expected return on plan assets	10.0%	9.5%	9.0%

In determining net periodic benefit costs, the Company uses fair value, as of the beginning of the year, as its basis for determining expected return on plan assets.

The following table displays the change in the benefit obligation, the fair value of plan assets and amounts included in the Company's Consolidated Balance Sheets as of December 31, 2002 and 2003 for the Company's postretirement benefit plans:

	December 31,	
	2002	2003
	(In millions)	
Change in Benefit Obligation		
Accumulated benefit obligation, beginning of year	$ 89	$ 41
Service cost	1	1
Interest cost	3	3
Benefits paid	—	(2)
Participant contributions	—	1
Plan amendments	3	(1)
Transfer to affiliate	(52)	—
Actuarial (gain) loss	(3)	1
Accumulated benefit obligation, end of year	$ 41	$ 44
Change in Plan Assets		
Plan assets, beginning of year	$ 37	$ 15
Benefits paid	—	(2)
Employer contributions	1	1
Participant contributions	—	1
Transfer to affiliate	(22)	—
Actual investment return	(1)	3
Plan assets, end of year	$ 15	$ 18
Reconciliation of Funded Status		
Funded status	$ (26)	$ (26)
Unrecognized transition obligation	8	7
Unrecognized prior service cost	13	11
Unrecognized actuarial loss	(5)	(5)
Net amount recognized at end of year	$ (10)	$ (13)
Amounts Recognized in Balance Sheets		
Benefit obligations	$ (10)	$ (13)
Net amount recognized at end of year	$ (10)	$ (13)

	December 31,	
	2002	2003
	(In millions)	
Actuarial Assumptions		
Discount rate	6.75%	6.25%
Expected long-term rate of return on assets	9.0%	8.5%
Healthcare cost trend rate assumed for the next year	11.25%	10.50%
Rate to which the cost trend rate is assumed to decline (ultimate trend rate)	5.5%	5.5%
Year that the rate reaches the ultimate trend rate	2011	2011
Measurement date used to determine plan obligations and assets	December 31, 2002	December 31, 2003

Assumed healthcare cost trend rates have a significant effect on the reported amounts for the Company's postretirement benefit plans. However, the effects of a 1% change in the assumed healthcare cost trend rate would change obligations and the total of service and interest costs by less than $1 million.

The following table displays the weighted average asset allocations as of December 31, 2002 and 2003 for the Company's postretirement benefit plan:

	December 31,	
	2002	2003
Domestic equity securities	35%	41%
International equity securities	8	9
Debt securities	54	48
Cash	3	2
Total	100%	100%

In managing the investments associated with the postretirement benefit plan, the Company's objective is to preserve and enhance the value of plan assets while maintaining an acceptable level of volatility. These objectives are expected to be achieved through an investment strategy, which manages liquidity requirements while maintaining a long-term horizon in making investment decisions and efficient and effective management of plan assets.

As part of the investment strategy discussed above, the Company has adopted and maintains the following asset allocation targets for its postretirement benefit plan:

Domestic equity securities	27-37%
International equity securities	5-15%
Debt securities	53-63%
Cash	0-2%

The expected rate of return assumption was developed by reviewing the targeted asset allocations and historical index performance of the applicable asset classes over a 15-year period, adjusted for investment fees and diversification effects.

The Company expects to contribute $1 million to its postretirement benefits plan in 2004.

(e) Postemployment Benefits

The Company participates in CenterPoint Energy's plan which provides postemployment benefits for former or inactive employees, their beneficiaries and covered dependents, after employment but before retirement (primarily healthcare and life insurance benefits for participants in the long-term disability plan). Postemployment benefits costs were less than $1 million for 2001 and 2002 and totaled $1 million for 2003.

(f) Other Non-Qualified Plans

The Company participates in CenterPoint Energy's non-qualified deferred compensation plans that provide benefits payable to directors, officers and certain key employees or their designated beneficiaries at specified future dates, upon termination, retirement or death. Benefit payments are made from the general assets of the Company. During 2001, 2002 and 2003, benefit expense relating to these programs was less than $1 million each year. Included in "Benefit Obligations" in the accompanying Consolidated Balance Sheets at both December 31, 2002 and 2003 was $4 million of liabilities relating to the deferred compensation plans.

(g) Other Employee Matters

As of December 31, 2003, the Company employed 1,511 people. Of these employees, 1,030 were covered by a collective bargaining agreement with the International Brotherhood of Electrical Workers Local 66 that expired in September 2003. The Company's bargaining unit employees have continued to work without interruption and the Company has not had any work interruptions since 1976. The Company continues to have a good relationship with the bargaining unit and is actively negotiating to obtain a new agreement in 2004.

(7) Income Taxes

The Company's current and deferred components of income tax expense (benefit) were as follows:

	Year Ended December 31,		
	2001	2002	2003
	(In millions)		
Current			
Federal	$ 91	$(24)	$73
State	25	—	—
Total current	116	(24)	73
Deferred			
Federal	(42)	(39)	(2)
State	—	—	—
Income tax expense (benefit)	$ 74	$(63)	$71

A reconciliation of the federal statutory income tax rate to the effective income tax rate is as follows:

	Year Ended December 31,		
	2001	2002	2003
		(In millions)	
Income (loss) before income taxes	$202	$(156)	$223
Federal statutory rate	35%	35%	35%
Income tax expense (benefit) at statutory rate	71	(55)	78
Increase (decrease) in tax resulting from:			
State income taxes, net of federal income tax benefit	16	—	—
Amortization of investment tax credit	(13)	(8)	(7)
Excess deferred taxes	(4)	—	—
Other, net	4	—	—
Total	3	(8)	(7)
Income tax expense (benefit)	$ 74	$ (63)	$ 71
Effective Rate	36.5%	40.3%	32.0%

The Company's tax effects of temporary differences between the carrying amounts of assets and liabilities in the financial statements and their respective tax bases were as follows:

	December 31,	
	2002	2003
	(In millions)	
Deferred tax assets:		
Non-current:		
Employee benefits	$ 4	$ 11
Environmental reserves	14	2
Other	4	4
Total non-current deferred tax assets	22	17
Deferred tax liabilities:		
Non-current:		
Depreciation	829	853
Other	6	9
Total non-current deferred tax liabilities	835	862
Accumulated deferred income taxes, net	$813	$845

The Company is included in the consolidated income tax returns of CenterPoint Energy. CenterPoint Energy's consolidated federal income tax returns have been audited and settled through the 1996 tax year. The 1997 through 2000 consolidated federal income tax returns are currently under audit.

(8) Commitments and Contingencies

(a) Fuel and Purchased Power Commitments

Fuel commitments include several long-term coal, lignite and natural gas contracts, which have various quantity requirements and durations that are not classified as non-trading derivatives assets and liabilities in

the Company's Consolidated Balance Sheets as of December 31, 2003 as these contracts meet the SFAS No. 133 exception to be classified as normal purchases contracts or do not meet the definition of a derivative. Minimum payment obligations related to coal and transportation agreements and lignite mining and lease agreements that extend through 2012 are approximately $309 million in 2004, $251 million in 2005, $256 million in 2006, $248 million in 2007 and $162 million in 2008. Purchase commitments related to purchased power are not material to the Company's operations. As of December 31, 2003, the pricing provisions in some of these contracts were above market.

(b) Lease Commitments

The following table sets forth information concerning the Company's obligations under non-cancelable long-term operating leases at December 31, 2003, which primarily consist of rental agreements for building space, data processing equipment and vehicles, including major work equipment (in millions).

2004	$11
2005	11
2006	10
2007	10
2008	10
2009 and beyond	47
Total	$99

Total lease expense for all operating leases was $10 million, $11 million and $11 million during 2001, 2002 and 2003, respectively.

(c) Environmental, Legal and Other

Clean Air Standards. The Texas electric restructuring law and regulations adopted by the Texas Commission on Environmental Quality (TCEQ) in 2001 require substantial reductions in emission of oxides of nitrogen (NOx) from electric generating units. The Company is currently installing cost-effective controls at its generating plants to comply with these requirements. Through December 31, 2003, the Company has invested $664 million for NOx emission control, and plans to make expenditures of up to approximately $131 million through 2007. Further revisions to these NOx standards may result from the TCEQ's future rules, expected by 2007, implementing more stringent federal eight-hour ozone standards.

Asbestos. The Company has been named, along with numerous others, as a defendant in several lawsuits filed by a large number of individuals who claim injury due to exposure to asbestos while working at sites along the Texas Gulf Coast. Most of these claimants have been workers who participated in construction of various industrial facilities, including power plants, and some of the claimants have worked at locations owned by the Company. The Company anticipates that additional claims like those received may be asserted in the future and intends to continue vigorously contesting claims which it does not consider to have merit.

Nuclear Insurance. The Company and the other owners of the South Texas Project maintain nuclear property and nuclear liability insurance coverage as required by law and periodically review available limits and coverage for additional protection. The owners of the South Texas Project currently maintain $2.75 billion in property damage insurance coverage, which is above the legally required minimum, but is less than the total amount of insurance currently available for such losses.

Under the Price Anderson Act, the maximum liability to the public of owners of nuclear power plants was $10.6 billion as of December 31, 2003. Owners are required under the Price Anderson Act to insure their liability for nuclear incidents and protective evacuations. The Company and the other owners currently

maintain the required nuclear liability insurance and participate in the industry retrospective rating plan under which the owners of the South Texas Project are subject to maximum retrospective assessments in the aggregate per incident of up to $100.6 million per reactor. The owners are jointly and severally liable at a rate not to exceed $10 million per incident per year. In addition, the security procedures at this facility have been enhanced to provide additional protection against terrorist attacks.

There can be no assurance that all potential losses or liabilities associated with the South Texas Project will be insurable, or that the amount of insurance will be sufficient to cover them. Any substantial losses not covered by insurance would have a material effect on the Company's financial condition, results of operations and cash flows.

Nuclear Decommissioning. CenterPoint Houston contributed $14.8 million in 2001 to trusts established to fund the Company's share of the decommissioning costs for the South Texas Project. CenterPoint Houston contributed $2.9 million in 2002 and 2003 to these trusts. There are various investment restrictions imposed upon the Company by the Texas Utility Commission and the United States Nuclear Regulatory Commission (NRC) relating to the Company's nuclear decommissioning trusts. The Company and CenterPoint Energy have each appointed two members to the Nuclear Decommissioning Trust Investment Committee which establishes the investment policy of the trusts and oversees the investment of the trusts' assets. The securities held by the trusts for decommissioning costs had an estimated fair value of $189 million as of December 31, 2003, of which approximately 37% were fixed-rate debt securities and the remaining 63% were equity securities. In July 1999, an outside consultant estimated the Company's portion of decommissioning costs to be approximately $363 million. While the funding levels currently exceed minimum NRC requirements, no assurance can be given that the amounts held in trust will be adequate to cover the actual decommissioning costs of the South Texas Project. Such costs may vary because of changes in the assumed date of decommissioning and changes in regulatory requirements, technology and costs of labor, materials and equipment. Pursuant to the Texas electric restructuring law, costs associated with nuclear decommissioning that have not been recovered as of January 1, 2002, will continue to be subject to cost-of-service rate regulation and will be included in a charge to transmission and distribution customers.

Joint Operating Agreement with City of San Antonio. The Company has a joint operating agreement with the City Public Service Board of San Antonio to share savings from the joint dispatching of each party's generating assets. Dispatching the two generating systems jointly results in savings of fuel and related expenses due to a more efficient utilization of each party's lowest cost resources. The two parties currently share equally the savings resulting from joint dispatch. The agreement terminates in 2009.

(9) Unaudited Quarterly Data

Summarized quarterly financial data is as follows:

	Year Ended December 31, 2002			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In millions, except per share data)			
Revenues	$ 326	$ 414	$ 526	$ 275
Operating income (loss)	(52)	(29)	7	(59)
Net income (loss)	(35)	(18)	3	(43)
Basic and diluted earnings per share	$(0.43)	$(0.23)	$0.04	$(0.54)

	Year Ended December 31, 2003			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In millions, except per share data)			
Revenues	$ 359	$ 578	$ 657	$ 408
Operating income (loss)	(17)	50	125	64
Income (loss) before cumulative effect of accounting change	(11)	33	82	47
Cumulative effect of accounting change, net of tax	99	—	—	—
Net income	88	33	82	47
Basic and diluted earnings per share:				
Income (loss) before cumulative effect of accounting change	$(0.14)	$0.42	$1.03	$0.58
Cumulative effect of accounting change, net of tax	1.24	—	—	—
Net income	$ 1.10	$0.42	$1.03	$0.58

(10) Subsequent Event

On February 5, 2004, the Company's board of directors declared a quarterly cash dividend of $0.25 per share of common stock payable on March 19, 2004 to shareholders of record as of the close of business on February 26, 2004.

INDEPENDENT AUDITORS' REPORT

To the Board of Directors and Shareholders of Texas Genco Holdings, Inc.:

We have audited the accompanying consolidated balance sheets of Texas Genco Holdings, Inc., (the Company), as of December 31, 2002 and 2003, and the related statements of consolidated operations, cash flows and capitalization and shareholders' equity for each of the three years in the period ended December 31, 2003. These financial statements are the responsibility of the Company'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 auditing standards generally accepted in the United States of America. 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, such consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2002 and 2003, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2003 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2(j) to the consolidated financial statements, on January 1, 2003, the Company recorded asset retirement obligations to conform to Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations."

DELOITTE & TOUCHE LLP

Houston, Texas
March 12, 2004

Item 9. *Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.*

None.

Item 9A. *Controls and Procedures.*

In accordance with Exchange Act Rules 13a-15 and 15d-15, we carried out an evaluation, under the supervision and with the participation of management, including our principal executive officer and principal financial officer, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2003 to provide assurance that information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms.

There has been no change in our internal controls over financial reporting that occurred during the three months ended December 31, 2003 that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

PART III

Item 10. *Directors and Executive Officers.*

The information called for by Item 10, to the extent not set forth in "Executive Officers" in Item 1 of this Form 10-K, is or will be set forth in the definitive proxy statement relating to Texas Genco's 2004 annual meeting of shareholders pursuant to SEC Regulation 14A. Such definitive proxy statement relates to a meeting of shareholders involving the election of directors and the portions thereof called for by Item 10 are incorporated herein by reference pursuant to Instruction G to Form 10-K.

Item 11. *Executive Compensation.*

The information called for by Item 11 is or will be set forth in the definitive proxy statement relating to Texas Genco's 2004 annual meeting of shareholders pursuant to SEC Regulation 14A. Such definitive proxy statement relates to a meeting of shareholders involving the election of directors and the portions thereof called for by Item 11 are incorporated herein by reference pursuant to Instruction G to Form 10-K.

Item 12. *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.*

The information called for by Item 12 is or will be set forth in the definitive proxy statement relating to Texas Genco's 2004 annual meeting of shareholders pursuant to SEC Regulation 14A. Such definitive proxy statement relates to a meeting of shareholders involving the election of directors and the portions thereof called for by Item 12 are incorporated herein by reference pursuant to Instruction G to Form 10-K.

Item 13. *Certain Relationships and Related Transactions.*

The information called for by Item 13 is or will be set forth in the definitive proxy statement relating to Texas Genco's 2004 annual meeting of shareholders pursuant to SEC Regulation 14A. Such definitive proxy statement relates to a meeting of shareholders involving the election of directors and the portions thereof called for by Item 13 are incorporated herein by reference pursuant to Instruction G to Form 10-K.

Item 14. *Principal Accountant Fees and Services.*

The information called for by Item 14 is or will be set forth in the definitive proxy statement relating to Texas Genco's 2004 annual meeting of shareholders pursuant to SEC Regulation 14A. Such definitive proxy

statement relates to a meeting of shareholders involving the election of directors and the portions thereof called for by Item 14 are incorporated herein by reference pursuant to Instruction G to Form 10-K.

PART IV

Item 15. ***Exhibits, Financial Statement Schedules and Reports on Form 8-K.***

(a)(1) *Financial Statements.*

Statements of Consolidated Operations for the Three Years Ended December 31, 2003	42
Consolidated Balance Sheets at December 31, 2002 and 2003	43
Statements of Consolidated Cash Flows for the Three Years Ended December 31, 2003	44
Statements of Consolidated Capitalization and Shareholders' Equity for the Three Years Ended December 31, 2003	45
Notes to Consolidated Financial Statements	46
Independent Auditors' Report	62

(a)(2) *Financial Statement Schedules for the Three Years Ended December 31, 2003*

The following schedules are omitted because of the absence of the conditions under which they are required or because the required information is included in the financial statements:

I, II, III, IV and V.

(a)(3) *Exhibits*

See Index of Exhibits on page 66.

(b) *Reports on Form 8-K*

On October 21, 2003, we filed a Current Report on Form 8-K dated October 21, 2003 in which we furnished information under Item 12 of that form relating to our third quarter 2003 earnings.

On December 12, 2003, we filed a Current Report on Form 8-K dated December 11, 2003 in which we announced that on December 9, 2003, one of three standby diesel generators at Unit 2 of the South Texas Project nuclear facility experienced a failure during a routine monthly surveillance test.

On January 29, 2004, we filed a Current Report on Form 8-K dated January 23, 2004 in which we announced that Reliant Resources, Inc. had notified CenterPoint Energy that it would not exercise its option to purchase CenterPoint Energy's 81% interest in Texas Genco Holdings, Inc.

On February 12, 2004, we filed a Current Report on Form 8-K dated February 12, 2004 in which we furnished information under Item 12 of that form relating to our fourth quarter and full year 2003 earnings.

On March 3, 2004, we filed a Current Report on Form 8-K dated March 3, 2004 to furnish under Item 9 of that form a slide presentation we expect will be presented to various members of the financial and investment community from time to time.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Houston, the State of Texas, on the 12th day of March, 2004.

TEXAS GENCO HOLDINGS, INC.
(Registrant)

By: /s/ DAVID G. TEES
David G. Tees
President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on March 12, 2004.

Signature	Title
/s/ DAVID G. TEES (David G. Tees)	President, Chief Executive Officer and Director (Principal Executive Officer)
/s/ GARY L. WHITLOCK (Gary L. Whitlock)	Executive Vice President, Chief Financial Officer and Director (Principal Financial Officer)
/s/ JAMES S. BRIAN (James S. Brian)	Senior Vice President and Chief Accounting Officer (Principal Accounting Officer)
/s/ J. EVANS ATTWELL (J. Evans Attwell)	Director
/s/ DONALD R. CAMPBELL (Donald R. Campbell)	Director
/s/ ROBERT J. CRUIKSHANK (Robert J. Cruikshank)	Director
/s/ PATRICIA A. HEMINGWAY HALL (Patricia A. Hemingway Hall)	Director
/s/ DAVID M. MCCLANAHAN (David M. McClanahan)	Director
/s/ SCOTT E. ROZZELL (Scott E. Rozzell)	Director

TEXAS GENCO HOLDINGS, INC.

EXHIBITS TO THE ANNUAL REPORT ON FORM 10-K
For Fiscal Year Ended December 31, 2003

INDEX OF EXHIBITS

Exhibits not incorporated by reference to a prior filing are designated by a cross (†); all exhibits not so designated are incorporated herein by reference to a prior filing as indicated.

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
3.1	— Amended and Restated Articles of Incorporation	Texas Genco Holdings, Inc.'s ("Texas Genco") Form 10-K for the year ended December 31, 2002	1-31449	3.1
3.2	— Amended and Restated Bylaws	Texas Genco's Form 10-K for the year ended December 31, 2002	1-31449	3.2
4.1	— Specimen Stock Certificate	Texas Genco's registration statement on Form 10	1-31449	4.1
10.1	— Separation Agreement between CenterPoint Energy, Inc. ("CenterPoint Energy") and Texas Genco effective as of August 31, 2002	Texas Genco's Form 10-K for the year ended December 31, 2002	1-31449	10.1
10.2	— Texas Genco Option Agreement	CenterPoint Energy Houston Electric, LLC's (formerly Reliant Energy, Incorporated) ("REI") quarterly report on Form 10-Q for the quarter ended March 31, 2001	1-3187	10.4
10.3	— Transition Services Agreement between CenterPoint Energy and Texas Genco effective as of August 31, 2002	Texas Genco's Form 10-K for the year ended December 31, 2002	1-31449	10.3
10.4	— Technical Services Agreement	CenterPoint Houston's quarterly report on Form 10-Q for the quarter ended March 31, 2001	001-31449	10.3
10.5	— Tax Allocation Agreement between CenterPoint Energy and Texas Genco effective as of August 31, 2002	Texas Genco's Form 10-K for the year ended December 31, 2002	1-31449	10.5
10.6(a)	— Executive Benefit Plan of CenterPoint and First and Second Amendments thereto effective as of June 1, 1982, July 1, 1984 and May 7, 1986, respectively	Houston Industries Incorporated's ("HI") Form 10-Q for the quarter ended March 31, 1987	1-7629	10(a)(1), (a)(2) and (a)(3)
10.6(b)	— Third Amendment to Exhibit 10.6(a) dated September 17, 1999	REI's Form 10-K for the year ended December 31, 2000	1-3187	10(a)(2)
10.7(a)	— Executive Life Insurance Plan of CenterPoint effective as of January 1, 1994	HI's Form 10-K for the year ended December 31, 1993	1-7629	10(q)
10.7(b)	— First Amendment to Exhibit 10.7(a) effective as of January 1, 1994	HI's Form 10-Q for the quarter ended June 30, 1995	1-7629	10
10.7(c)	— Second Amendment to Exhibit 10.7(a) effective as of August 6, 1997	REI's Form 10-K for the year ended December 31, 1997	1-3187	10(s)(3)

Exhibit Number		Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
10.8(a)	—	Long-Term Incentive Compensation Plan of CenterPoint effective as of January 1, 1989	HI's Form 10-Q for the quarter ended June 30, 1989	1-7629	10(c)
10.8(b)	—	First Amendment to Exhibit 10.8(a) effective as of January 1, 1990	HI's Form 10-K for the year ended December 31, 1989	1-7629	10(f)(2)
10.8(c)	—	Second Amendment to Exhibit 10.8(a) effective as of December 22, 1992	HI's Form 10-K for the year ended December 31, 1992	1-7629	10(u)(3)
10.8(d)	—	Third Amendment to Exhibit 10.8(a) effective as of August 6, 1997	REI's Form 10-K for the year ended December 31, 1997	1-3187	10(m)(4)
10.9	—	Retention Agreement effective October 15, 2001 between REI and David G. Tees	REI's Form 10-K for the year ended December 31, 2001	1-3187	10(jj)
10.10(a)	—	Deferred Compensation Plan of CenterPoint effective as of January 1, 1991	HI's Form 10-K for the year ended December 31, 1990	1-7629	10(d)(3)
10.10(b)	—	First Amendment to Exhibit 10.10(a) effective as of January 1, 1991	HI's Form 10-K for the year ended December 31, 1991	1-7629	10(j)(2)
10.10(c)	—	Second Amendment to Exhibit 10.10(a) effective as of March 30, 1992	HI's Form 10-Q for the quarter ended March 31, 1992	1-7629	10(g)
10.10(d)	—	Third Amendment to Exhibit 10.10(a) effective as of June 2, 1993	HI's Form 10-K for the year ended December 31, 1993	1-7629	10(j)(4)
10.10(e)	—	Fourth Amendment to Exhibit 10.10(a) effective as of December 1, 1993	HI's Form 10-K for the year ended December 31, 1993	1-7629	10(j)(5)
10.10(f)	—	Fifth Amendment to Exhibit 10.10(a) effective as of September 7, 1994	HI's Form 10-K for the year ended December 31, 1994	1-7629	10(j)(6)
10.10(g)	—	Sixth Amendment to Exhibit 10.10(a) effective as of August 1, 1995	HI's Form 10-Q for the quarter ended June 30, 1995	1-7629	10(b)
10.10(h)	—	Seventh Amendment to Exhibit 10.10(a) effective as of December 1, 1995	HI's Form 10-Q for the quarter ended June 30, 1996	1-7629	10(d)
10.10(i)	—	Eighth Amendment to Exhibit 10.10(a) effective as of January 1, 1997	HI's Form 10-Q for the quarter ended June 30, 1997	1-7629	10(d)
10.10(j)	—	Ninth Amendment to Exhibit 10.10(a) effective in part August 6, 1997, in part October 1, 1997 and in part January 1, 1998	REI's Form 10-K for the year ended December 31, 1997	1-3187	10(1)(10)
10.10(k)	—	Tenth Amendment to Exhibit 10.10(a) effective as of September 3, 1997	REI's Form 10-K for the year ended December 31, 1997	1-3187	
10.11	—	Assignment and Assumption Agreement for the Technical Services Agreement entered into as of August 31, 2002, by and between Texas Genco, LP and REI	Texas Genco's registration statement on Form 10	1-31449	10.11

Exhibit Number		Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
10.12	—	Undertaking to Comply with Certain Provisions of Option Agreement entered into as of August 31, 2002 by Texas Genco	Texas Genco's registration statement on Form 10	1-31449	10.12
10.13	—	Amendment No. 1 to Texas Genco Option Agreement dated February 21, 2003	Texas Genco's Form 10-K for the year ended December 31, 2002	1-31449	10.13
10.14	—	$75,000,000 revolving credit facility dated as of December 23, 2003 among Texas Genco, LP and the banks named therein	CenterPoint Energy Inc.'s ("CNP") Form 10-K for the year ended December 31, 2003	1-31447	10(pp)(1)
10.15	—	First mortgage indenture, dated as of December 23, 2003 among Texas Genco, LP and JPMorgan Chase Bank, as trustee	CNP's Form 10-K for the year ended December 31, 2003	1-31447	10(pp)(2)
10.16	—	First supplemental indenture to Exhibit 10.15 dated as of December 23, 2003	CNP's Form 10-K for the year ended December 31, 2003	1-31447	10(pp)(3)
10.17	—	Pledge Agreement, dated as of October 7, 2003, executed in connection with Credit Agreement, dated as of October 7, 2003, among CenterPoint Energy and the banks named therein	CNP's Form 10-Q for the quarter ended September 30, 2003	1-31447	10.9
10.18	—	CenterPoint Energy 1985 Deferred Compensation Plan, as amended and restated effective January 1, 2003	CNP's Form 10-Q for the quarter ended September 30, 2003	1-31447	10.1
10.19	—	CenterPoint Energy Deferred Compensation Plan, as amended and restated effective January 1, 2003	CNP's Form 10-Q for the quarter ended September 30, 2003	1-31447	10.2
10.20	—	CenterPoint Energy Short Term Incentive Plan, as amended and restated effective January 1, 2003	CNP's Form 10-Q for the quarter ended September 30, 2003	1-31447	10.3
10.21	—	CenterPoint Energy Executive Benefits Plan, as amended and restated effective January 1, 2003	CNP's Form 10-Q for the quarter ended September 30, 2003	1-31447	10.4
10.22	—	CenterPoint Energy Executive Life Insurance Plan, as amended and restated effective June 18, 2003	CNP's Form 10-Q for the quarter ended September 30, 2003	1-31447	10.5
10.23	—	Texas Genco Holdings, Inc. Performance Unit Plan effective January 1, 2003	Texas Genco's Form 10-Q for the quarter ended September 30, 2003	1-31449	10.7
21.1	—	Subsidiaries of Texas Genco	Texas Genco's registration statement on Form 10	1-31449	21.1
†31.1	—	Rule 13a-14(a)/15d-14(a) Certification of David G. Tees			
†31.2	—	Rule 13a-14(a)/15d-14(a) Certification of Gary L. Whitlock			
†32.1	—	Section 1350 Certification of David G. Tees			
†32.2	—	Section 1350 Certification of Gary L. Whitlock			

South Texas Project Electric Generating Station and South Texas Project Nuclear Operating Company

Special Purpose Project Statements
Years Ended December 31, 2003 and 2002 and
Independent Auditors' Report

SOUTH TEXAS PROJECT ELECTRIC GENERATING STATION AND STP NUCLEAR OPERATING COMPANY

TABLE OF CONTENTS

	Page
INDEPENDENT AUDITORS' REPORT	1-2
SPECIAL PURPOSE PROJECT STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2003 AND 2002:	
STPEGS and STPNOC Combined Statements of Owners' Assets	3
STPEGS and STPNOC Combined Balance Sheets	4
STPEGS and STPNOC Combined Statements of Expenses and Miscellaneous Income (Deductions)	5-6
STPEGS and STPNOC Combined Statements of Selected Cash Flows	7-8
STPEGS and STPNOC Combined Statements of Owners' Liabilities	9
Notes to Special Purpose Project Statements	10-15

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INDEPENDENT AUDITORS' REPORT

Texas Genco, L.P., the City of San Antonio (acting through the City Public Service Board), AEP Texas Central Company, and the City of Austin (acting through Austin Energy) (collectively, the "Participants")

We have audited the following special purpose project statements as of or for the years ended December 31, 2003 and 2002 for South Texas Project Electric Generating Station ("STPEGS"), South Texas Project Nuclear Operating Company ("STPNOC") and combined STPEGS and STPNOC, collectively, the "special purpose project statements:"

STPEGS and STPNOC Combined Statements of Owners' Assets as of December 31, 2003 and 2002,

STPEGS and STPNOC Combined Balance Sheets as of December 31, 2003 and 2002,

STPEGS and STPNOC Combined Statements of Expenses and Miscellaneous Income (Deductions) for the years ended December 31, 2003 and 2002,

STPEGS and STPNOC Combined Statements of Selected Cash Flows for the years ended December 31, 2003 and 2002, and

STPEGS AND STPNOC Combined Statements of Owners' Liabilities as of December 31, 2003 and 2002.

These accompanying special purpose project statements are the responsibility of STPNOC's management. Our responsibility is to express an opinion on these special purpose project statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the special purpose project statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the special purpose project statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall special purpose project statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As described in Note 1, these special purpose project statements were prepared for the purpose of complying with the requirements of Paragraph 9.3.4 of the Amended and Restated South Texas Project Participation Agreement ("Participation Agreement") dated November 17, 1997, and are not intended to be a presentation in conformity with accounting principles generally accepted in the United States of America.

In our opinion, such special purpose project statements described in the first paragraph above present fairly, in all material respects, the combined STPEGS and STPNOC project statement information on the basis of accounting described in Note 1.

This report is intended solely for the information and use of the Participants and is not intended to be and should not be used by anyone other than these specified parties.

Deloitte & Touche LLP

March 9, 2004

SOUTH TEXAS PROJECT ELECTRIC GENERATING STATION AND STP NUCLEAR OPERATING COMPANY

COMBINED STATEMENTS OF OWNERS' ASSETS
DECEMBER 31, 2003 AND 2002

Account Number	ASSETS	2003	2002
101.0	Electric plant in-service	$ 5,914,331,864	$ 5,828,581,523
107	Construction work-in-progress	1,471,457	158,146,039
108	Accumulated provision for depreciation of electric plant in-service	56,995,973	(19,311,786)
120.1	Nuclear fuel in process	30,695,532	40,803,063
120.2	Nuclear fuel in stock	409,825	3,182,586
120.3	Nuclear fuel assemblies	213,958,129	213,347,728
120.4	Spent nuclear fuel	808,995,212	757,652,353
120.5	Accumulated provision for amortization of nuclear fuel	(922,282,293)	(876,677,775)
131	Cash	96,253	60,270
135	Working funds	5,815	9,972
143	Other accounts receivable	632,398	54,226
154	Materials and supplies	89,184,244	86,812,893
163	Stores expense undistributed		1,612,523
165	Prepayments	2,778,841	3,588,432
184	Clearing accounts		
186.2	Other work-in-progress	22,553	1,154,961
186.4	Enrichment decommissioning and decontamination receivable from owners	21,698,519	21,506,292
186.5	Accumulated provision for amortization of enrichment decommissioning and decontamination	(13,167,380)	(10,928,453)
186.6	Pension intangible asset	3,991,151	3,685,064
	Total owners' assets	6,209,818,093	6,213,279,911
	Contra asset summary	(6,209,818,093)	(6,213,279,911)
	TOTAL	$ -	$ -

The accompanying notes are an integral part of these special purpose project statements.

SOUTH TEXAS PROJECT ELECTRIC GENERATING STATION AND STP NUCLEAR OPERATING COMPANY

COMBINED BALANCE SHEETS
DECEMBER 31, 2003 AND 2002

Account Number	ASSETS	2003	2002
146	Total receivables from owners	$ 100,333,508	$ 101,370,444
	TOTAL	$ 100,333,508	$ 101,370,444
	LIABILITIES		
	CURRENT AND ACCRUED LIABILITIES		
228.2	Injuries and damages reserve	$ 775,581	$ 803,186
232	Accounts payable	7,485,447	13,412,685
232	Accrued liabilities	12,194,654	25,934,632
232	Accrued payroll and related expenses	1,614,410	2,635,187
236	Accrued payroll taxes	624,833	436,828
242	Accrued spent fuel disposal fee	5,267,125	2,659,320
242	Other miscellaneous liabilities		375,000
242	Incentive compensation and benefits accruals—current	9,363,857	5,385,889
242	Enrichment decomissioning and decontamination liability—current	2,274,970	2,226,914
253	Other deferred credits	6,483,621	5,542,859
	Total current and accrued liabilities	46,084,498	59,412,500
	OTHER LIABILITIES		
228.3	Other postretirement benefit liability	21,208,050	18,191,365
228.3	Postemployment benefit liability	430,074	533,400
228.3	Pension liability	28,060,945	16,552,438
228.4	Enrichment decomissioning and decontamination liability—noncurrent	4,549,941	6,680,741
	Total other liabilities	54,249,010	41,957,944
	TOTAL	$ 100,333,508	$ 101,370,444

The accompanying notes are an integral part of these special purpose project statements.

SOUTH TEXAS PROJECT ELECTRIC GENERATING STATION AND STP NUCLEAR OPERATING COMPANY

COMBINED STATEMENTS OF EXPENSES AND MISCELLANEOUS INCOME (DEDUCTIONS)
YEARS ENDED DECEMBER 31, 2003 AND 2002

Account Number		2003	2002
	Miscellaneous Income (Deductions)		
421	Miscellaneous nonoperating income	$ 9,311	$ 432,420
426	Other income (deductions)	(68,437)	(74,011)
	Total miscellaneous income (deductions)	(59,126)	358,409
	Production Expenses		
	OPERATIONS:		
517	Supervision and engineering	33,098,541	31,091,965
519	Coolants and water	4,445,120	4,119,475
520	Steam expenses	3,818,334	3,355,537
523	Electric expenses	17,815,274	16,624,123
524	Miscellaneous nuclear power expenses	37,664,066	34,462,427
525	Rent	181	209
	Total operations expenses	96,841,516	89,653,736
	MAINTENANCE:		
528	Supervision and engineering	21,068,696	19,614,439
529	Structures	7,278,593	5,964,351
530	Reactor plant equipment	46,510,274	20,363,732
531	Electric plant	19,727,051	22,137,710
532	Miscellaneous nuclear plant	3,421,608	3,124,698
	Total maintenance expenses	98,006,222	71,204,930
	FUEL:		
518.101/201	Nuclear fuel amortization	45,604,518	52,309,901
518.103/203	Nuclear fuel disposal fees	14,736,438	17,927,717
518.104/204	Amortization of enrichment decomissioning and decontamination	2,238,928	2,197,333
518.105/205	Nuclear fuel credits		
	Total fuel expenses	62,579,884	72,434,951
	Total production expenses	257,427,622	233,293,617

The accompanying notes are an integral part of these special purpose project statements.

(Continued)

SOUTH TEXAS PROJECT ELECTRIC GENERATING STATION AND STP NUCLEAR OPERATING COMPANY

COMBINED STATEMENTS OF EXPENSES AND MISCELLANEOUS INCOME (DEDUCTIONS)
YEARS ENDED DECEMBER 31, 2003 AND 2002

Account Number		2003	2002
	ADMINISTRATIVE AND GENERAL EXPENSES		
920	Administrative and general salaries	12,415,007	11,808,707
921	Office supplies and expenses	2,368,273	2,550,642
923	Outside services employed	3,596,851	3,584,214
924	Nuclear property insurance	1,548,668	886,265
925	Injuries and damages	1,636,444	(2,335,286)
926	Employee pensions and other benefits	29,719,632	23,592,255
930	Miscellaneous general expenses	3,747,241	4,038,809
935	Maintenance of general plant	5,060,583	3,009,871
408	Taxes other than income taxes	7,495,435	7,182,310
	Total administrative and general expenses	67,588,134	54,317,787
	Total operating expenses	325,015,756	287,611,404
	Total expenses and miscellaneous income (deductions)	325,074,882	287,252,995
457	Allocation to owners	(325,074,882)	(287,252,995)
	NET INCOME	$ -	$ -

The accompanying notes are an integral part of these special purpose project statements. (Concluded)

SOUTH TEXAS PROJECT ELECTRIC GENERATING STATION AND STP NUCLEAR OPERATING COMPANY

COMBINED STATEMENTS OF SELECTED CASH FLOWS
YEARS ENDED DECEMBER 31, 2003 AND 2002

	2003	2002
CASH FLOWS USED IN OPERATING ACTIVITIES:		
Expenses and miscellaneous income (deductions)	$(325,074,882)	$(287,252,995)
Adjustments to reconcile net expenses and miscellaneous income (deductions) to net cash used in operating activities:		
Amortization of enrichment decommissioning and decontamination assessment	2,238,928	2,197,333
Amortization of nuclear fuel	45,604,518	52,309,901
Change in inventory—nuclear fuel	(39,072,968)	(76,919,996)
Change in inventory—materials and supplies	(2,371,351)	(255,944)
Change in other accounts receivable	(578,172)	78,352
Change in prepayments	809,591	(182,905)
Change in undistributed stores expense	1,612,523	(435,726)
Change in enrichment decommissioning and decontamination assessment	(192,227)	(197,207)
Change in clearing accounts		61,701
Change in other assets	830,477	(2,965,742)
Change in accounts payable and accrued liabilities	(19,667,216)	28,019,222
Change in accrued payroll and related expenses	(832,772)	1,864,823
Change in enrichment decommissioning and decontamination—current	48,056	39,442
Change in enrichment decommissioning and decontamination—noncurrent	(2,130,800)	(2,069,147)
Change in incentive compensation accrued	4,918,730	(4,162,880)
Change in injuries and damages reserve	(27,605)	(364,636)
Change in accrued spent fuel disposal fee	2,607,805	(1,713,069)
Change in other miscellaneous accrued liabilities	(375,000)	20,775
Change in postemployment benefits liability	(103,326)	165,400
Change in pension liability	7,223,146	2,307,451
Change in other postretirement benefits liability	3,016,685	(5,718,446)
Change in owners receivables due to additional minimum pension liability	(3,979,274)	(5,807,235)
Change in additional minimum pension liability	4,285,361	9,492,299
Total adjustments	3,865,109	(4,236,235)
Net cash used in operating activities	(321,209,773)	(291,489,229)
CASH FLOWS FROM INVESTING ACTIVITIES—Capital expenditures	(5,383,518)	(27,134,630)
CASH FLOWS FROM FINANCING ACTIVITIES—Cash funding from owners	326,629,274	318,626,904
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	35,983	3,045
CASH AND CASH EQUIVALENTS—Beginning of year	60,270	57,225
CASH AND CASH EQUIVALENTS—End of year	$ 96,253	$ 60,270

The accompanying notes are an integral part of these special purpose project statements.

(Continued)

SOUTH TEXAS PROJECT ELECTRIC GENERATING STATION AND STP NUCLEAR OPERATING COMPANY

COMBINED STATEMENTS OF SELECTED CASH FLOWS
YEARS ENDED DECEMBER 31, 2003 AND 2002

	Texas Genco, L.P.	City of San Antonio	AEP Texas Central Company	City of Austin	Total
December 31, 2003					
Cash funding from owners:					
Operations	$ 96,875,886	$88,037,529	$79,262,089	$50,325,136	$314,500,640
Spent fuel disposal fee	3,694,111	3,402,558	3,070,454	1,961,511	12,128,634
TOTAL	$100,569,997	$91,440,087	$82,332,543	$52,286,647	$326,629,274
December 31, 2002					
Cash funding from owners:					
Operations	$ 92,045,766	$83,814,196	$75,310,173	$47,815,982	$298,986,117
Spent fuel disposal fee	6,013,676	5,528,860	4,933,733	3,164,518	19,640,787
TOTAL	$ 98,059,442	$89,343,056	$80,243,906	$50,980,500	$318,626,904

The accompanying notes are an integral part of these special purpose project statements.

(Concluded)

SOUTH TEXAS PROJECT ELECTRIC GENERATING STATION AND STP NUCLEAR OPERATING COMPANY

COMBINED STATEMENTS OF OWNERS' LIABILITIES
DECEMBER 31, 2003 AND 2002

	Texas Genco, L.P.	City of San Antonio	AEP Texas Central Company	City of Austin	Total
December 31, 2003					
South Texas Project Electric Generating Station:					
Accrued spent fuel disposal fee	$ 1,624,955	$ 1,464,233	$ 1,329,555	$ 848,382	$ 5,267,125
Enrichment decommissioning and decontamination liability	2,102,073	1,910,975	1,719,877	1,091,986	6,824,911
Accounts payable	6,061,471	5,510,428	4,959,386	3,148,816	19,680,101
Other liabilities	238,879	217,163	195,447	124,093	775,582
STP Nuclear Operating Company:					
Incentive compensation and benefit accruals	4,881,023	4,437,294	3,993,564	2,535,596	15,847,477
Other liabilities	15,997,000	14,542,727	13,088,455	8,310,130	51,938,312
Adjustment for CPSB funding	32,268	(75,432)	26,401	16,763	
Total owners' liabilities	$30,937,669	$28,007,388	$25,312,685	$16,075,766	$100,333,508
December 31, 2002					
South Texas Project Electric Generating Station:					
Accrued spent fuel disposal fee	$ 797,683	$ 753,993	$ 675,519	$ 432,125	$ 2,659,320
Enrichment decommissioning and decontamination liability	2,743,558	2,494,143	2,244,729	1,425,225	8,907,655
Accounts payable	12,118,973	11,017,249	9,915,524	6,295,571	39,347,317
Other liabilities	362,881	329,892	296,903	188,510	1,178,186
STP Nuclear Operating Company:					
Incentive compensation and benefit accruals	3,366,055	3,060,049	2,754,044	1,748,600	10,928,748
Other liabilities	11,811,559	10,737,781	9,664,003	6,135,875	38,349,218
Adjustment for CPSB funding	41,958	(98,083)	34,329	21,796	
Total owners' liabilities	$31,242,667	$28,295,024	$25,585,051	$16,247,702	$101,370,444

The accompanying notes are an integral part of these special purpose project statements.

SOUTH TEXAS PROJECT ELECTRIC GENERATING STATION AND STP NUCLEAR OPERATING COMPANY

NOTES TO SPECIAL PURPOSE PROJECT STATEMENTS YEARS ENDED DECEMBER 31, 2003 AND 2002

1. THE PROJECT AND ITS SIGNIFICANT ACCOUNTING POLICIES

The South Texas Project Electric Generating Station ("STPEGS") consists of two 1,250-megawatt nuclear steam electric generating units and all interests in property, facilities and structures used therewith or related thereto on or adjacent to the South Texas Project ("STP") site, a parcel of land in Matagorda County, Texas, consisting of approximately 12,200 acres.

The Amended and Restated South Texas Project Participation, Operating and Transition Agreements ("Agreements"), dated November 17, 1997, provide for the licensing, construction, operation and maintenance of the jointly owned and operated electric generation facilities of STPEGS. The Participants are: Texas Genco, L.P., a successor in ownership to Reliant Energy, Incorporated, ("Texas Genco") the City of San Antonio, acting through the City Public Service Board of San Antonio ("CPSB"), AEP Texas Central Company ("AEP") and the City of Austin, acting through Austin Energy ("Austin") (collectively, the "Participants"). Ownership percentages are 30.8%, 28.0%, 25.2% and 16.0% for Texas Genco, CPSB, AEP and Austin, respectively.

Effective October 1, 1997, the Participants formed an operating company, STP Nuclear Operating Company ("STPNOC"), which performs all responsibilities previously performed by the predecessor to Texas Genco, as project manager. STPNOC is considered a not-for-profit entity for taxation purposes and all operating expenses are incurred on behalf of STPEGS and are fully reimbursed by the Participants. As of December 31, 2003 and 2002, and for the years then ended, STPNOC was the project manager for all aspects of STPEGS except for the construction, operation and maintenance of power and transmission lines, for which AEP is responsible, and switchyard maintenance, for which Texas Genco is responsible. Procurement of nuclear fuel (other than fabrication) is the responsibility of the owners.

Basis of Accounting and Account Classifications—The accounting records of STPEGS and STPNOC, collectively "the Project" are maintained on the accrual basis of accounting, as required by the Project's Conduct of Accounting Policy, and are in compliance with generally accepted accounting principles in the United States of America except for, but not limited to, project financing, ad valorem taxes, sales and use tax, depreciation, and decommissioning expense which are not considered in the records of the Project or in these special purpose project statements.

The accounting records are also maintained and the accompanying amounts are classified in accordance with the Agreements and with the Federal Energy Regulatory Commission's "Uniform System of Accounts Prescribed for Public Utilities and Licensees," as adopted by the Public Utility Commission of Texas ("PUCT").

The financial statements have been modified effective December 2002 to reflect both STPEGS and STPNOC financial information. Labor related liabilities, were previously broken out in a separate STPNOC balance sheet due to the affiliate transaction rules of the PUCT. However, subsequent to deregulation of the electric generation industry in the state of Texas, there is no longer a reason to show them separately. Instead, all liabilities (labor and non-labor related) are now presented in one financial statement.

Use of Estimates—Preparation of these special purpose project statements in conformity with the Agreements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and reported amounts of expenses during the period. Actual results could differ from these estimates.

Electric Plant In-Service—Electric plant in-service is stated at the original cost of construction which includes the cost of contracted services, direct labor, materials and overhead items. Additions to electric plant in-service, betterments to existing property and replacements of units of property are capitalized at cost. Maintenance repairs and minor replacement costs are charged to operating expense when incurred.

Construction Work in Progress—Construction work-in-progress includes capital modifications or additions to electric plant in-service. Expenditures are accumulated and classified through work orders. As work orders are completed and the asset is placed in-service, the related costs are transferred to electric plant in-service.

Accumulated Provision for Depreciation of Electric Plant In-Service—Upon retirement, the historical cost of the asset removed from service, net of salvage value plus the cost to retire, is accumulated through work orders and transferred from electric plant in-service to accumulated provision for depreciation of electric plant in-service on the Statements of Owners' Assets. The historical cost of the asset is the unitized value which is based on allocated construction costs determined principally from engineering estimates. At December 31, 2003 and 2002, this account includes warranty credits received from equipment vendors. STPEGS accounts for these credits as salvage value received prior to the retirement of warranty equipment.

Nuclear Fuel—Nuclear fuel includes nuclear fuel materials as well as refinement, conversion, enrichment and fabrication costs incurred to produce nuclear fuel assemblies. Nuclear fuel assemblies are amortized using a units-of-production method whereby an amortization rate is derived by dividing the unamortized value of an assembly by the calculated remaining million British thermal units ("MMBTUs") for such assembly. Amortization expense is then computed from measurements of MMBTUs produced by each fuel assembly, multiplied by the previously determined amortization rate.

Materials and Supplies—Materials and supplies are carried at the lower of average cost or net realizable value. During the years ended December 31, 2003 and 2002, STPEGS wrote off $317,000 and $402,000, respectively, of excess and obsolete materials and supplies as a result of the Project's ongoing assessment of its inventory.

Enrichment Decommissioning and Decontamination Assessment and Liability—As of December 31, 2003, STPEGS has three years remaining for payment of a Department of Energy Enrichment Decommissioning and Decontamination Assessment. STPEGS accounts for the remaining amount as a liability and a receivable from the Participants. Included in the receivable (account 186.4) amount is an asset for the prepayment of nine months of Enrichment Decommissioning and Decontamination Assessment.

Operating Costs—Under the provisions of the Agreements, costs incurred to operate STPEGS are shared by the Participants in the same proportion as their respective ownership percentages in the generating unit and common facilities, except for the spent fuel disposal fee which is shared based on each participants portion of electricity generated and sold.

Federal Income Tax Status—No provision for federal income taxes has been recorded in the accompanying project statements as each Participant is responsible for the reporting and payment of such taxes. STPNOC has filed a corporate tax return for 2002 which indicates that it has no taxable income. A similar tax filing requirement exists for 2003.

Reclassifications—Some amounts for the previous year have been reclassified to conform to the 2003 presentation of financial statements. These reclassifications do not affect the statements of expenses and miscellaneous income (deductions).

2. PENSION PLANS AND OTHER POSTRETIREMENT BENEFITS

STPNOC has a noncontributory defined benefit pension plan covering most employees. This plan provides benefits that are based on years of service and the employee's highest paid consecutive 36 months during the last 120 months before termination of employment. The assets in the plan at December 31, 2003 and 2002 were invested in various equity and fixed income securities. For the 2003 plan year, an additional contribution of approximately $2.7 million will be made in September 2004. For the 2002 plan year, no additional contribution is required due to a final 2001 contribution of approximately $7.6 million, which was made in September 2002.

Employees whose pension benefits exceed the $200,000 Employee Retirement Income Security Act limitations are covered by a supplementary nonqualified, unfunded pension plan which is being provided for by charges to STPEGS's expense sufficient to meet the projected benefit obligations. The accruals for the cost of this plan are based on substantially the same actuarial methods and economics as the noncontributory defined benefit pension plan.

STPNOC has a defined benefit postretirement plan that provides medical, dental and life insurance benefits for substantially all retirees and eligible dependents. STPNOC retains the right to change or terminate these benefits. The cost of these benefits is recognized in the financial statements during an employee's active working career with STPNOC. STP has a trust to partially meet the obligations of the plan.

	Pension Benefits		Other Benefits	
	2003	2002	2003	2002
Change in benefit obligation:				
Benefit obligation—beginning of period	$ 91,796,456	$ 74,345,015	$ 39,272,037	$ 27,195,753
Service cost	4,907,173	3,871,655	2,914,518	2,592,352
Interest cost	6,132,465	5,316,231	2,578,149	1,927,701
Amendments	721,889	3,275,089		(6,627,282)
Actuarial loss	11,907,596	6,788,466	8,509,771	15,826,025
Benefits paid	(1,860,000)	(1,800,000)	(2,568,287)	(1,642,512)
Benefit obligation—end of period	113,605,579	91,796,456	50,706,188	39,272,037
Change in plan assets:				
Fair value of plan assets—beginning of period	59,622,815	55,551,660	9,145,039	10,142,448
Actual return on plan assets	10,318,336	(3,656,412)	1,219,748	(883,841)
Employer contributions		9,527,567	2,068,946	1,528,944
Benefits paid	(1,860,000)	(1,800,000)	(2,568,287)	(1,642,512)
Fair value of plan assets—end of period	68,081,151	59,622,815	9,865,446	9,145,039
Funded status—end of period	(45,524,428)	(32,173,641)	(40,840,742)	(30,126,998)
Unrecognized net actuarial loss	27,249,992	21,428,438	21,622,066	14,157,092
Unrecognized prior service cost	3,991,151	3,685,064	(2,585,634)	(2,872,927)
Unrecognized transition obligation			596,260	651,469
Additional minimum pension liability	(13,777,660)	(9,492,299)		
Accrued benefit cost	$(28,060,945)	$(16,552,438)	$(21,208,050)	$(18,191,364)
Weighted-average assumptions:				
Discount rate	6.25%	6.75%	6.25%	6.75%
Expected return on plan assets	9.00%	9.00%	9.00%	9.00%
Rate of compensation increase	3.00%	3.00%	3.00%	3.00%

	Pension Benefits		Other Benefits	
	2003	2002	2003	2002
Components of net periodic benefit cost:				
Service cost	$ 4,907,173	$ 3,871,655	$2,914,518	$2,592,352
Interest cost	6,132,465	5,316,231	2,578,149	1,927,701
Expected return on plan assets	(5,280,992)	(5,420,051)	(813,579)	(896,520)
Amortization of prior service cost	415,802	129,768	(287,293)	
Amortization of transition (asset) obligation		(88,482)	55,209	373,374
Recognized net actuarial (gain) loss	1,048,698		638,627	(160,512)
Net periodic benefit cost	$ 7,223,146	$ 3,809,121	$5,085,631	$3,836,395

Actuarial estimates for STPNOC's postretirement benefit plan assumed a weighted average annual rate of increase in the per capita costs of covered health care benefits of 10.00% for 2004 trending down to 4.50% for 2009 and beyond. 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 trend rates would have the following effects:

	2003	2002
One-percentage-point increase:		
Effect on total of service and interest cost components	$ 912,425	$ 678,421
Effect on postretirement benefit obligation	6,381,042	4,521,154
One-percentage-point decrease:		
Effect on total of service and interest cost components	(745,921)	(560,583)
Effect on postretirement benefit obligation	(5,327,177)	(3,824,397)

STPNOC has a contributory savings plan for substantially all employees. STPNOC contributes 70% of an employee's contribution up to 6% of an employee's salary. Expenses recognized for contributions during 2003 and 2002 were approximately $3,933,000 and $3,948,000, respectively.

STPNOC has deferred compensation programs and supplemental retirement plans with certain key individuals. These additional benefits are non-funded. As of December 31, 2003 and 2002, accrued liabilities associated with these additional benefits were approximately $5,769,000 and $5,543,000, respectively.

3. COMMITMENTS, CONTINGENCIES AND OTHER

The Project is a party to various claims and lawsuits resulting from normal construction and operating activities. While the ultimate outcome is not currently determinable, project management believes that any future costs associated with these actions will be immaterial to these statements.

Employers National Insurance Company, the Project's Insurance Carrier for Workers' Compensation and General Liability for the policy periods October 1983 through December 1990, is currently in "receivership" status. STPEGS and the Special Deputy Receiver reached a settlement related to these policy periods of $330,000, which was paid in full at December 31, 2002.

The Participants maintain nuclear property and nuclear liability insurance coverage as required by law and periodically review available limits and coverage for additional protection. There can be no assurance that all potential losses or liabilities will be insurable or that the amount of insurance will be sufficient to cover them. Any losses not covered by insurance would be borne by the Participants.

4. SUPPLEMENTAL DISCLOSURES TO THE COMBINED STATEMENT OF SELECTED CASH FLOWS

Noncash investing activities included in the statement of cash flows were approximately $690,000 and $(16.3) million for the years ended December 31, 2003 and 2002, respectively. These items represent capital retirements (net of salvage) and other noncash items related to the plant.

5. SUPPLEMENTAL DISCLOSURE TO THE COMBINED STATEMENT OF OWNERS' LIABILITIES

On December 31, 2003 and 2002 CPSB had over funded its ownership interest by $104,761 and $136,226, respectively, due to estimated funding. A corresponding reduction from their January 2003 payment reduced this over funding. Adjustments were made to the owners' liabilities to reflect the actual receivable by owner.

6. NEW ACCOUNTING PRONOUNCEMENTS

In June 2002, the FASB issued SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities* ("SFAS No. 146"). SFAS No. 146 nullifies EITF Issue No. 94-3, *Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)* ("EITF No. 94-3"). The principal difference between SFAS No. 146 and EITF No. 94-3 for STP relates to the recognition of one-time termination costs. SFAS No. 146 requires that once a firm plan of termination is communicated to employees, then the entire liability for severance payments is recognized at that date, if the employees will be terminated within a minimal retention period. However, if the employees are retained past the minimal retention period, and are required to render this service in order to receive severance benefits, then the liability will be recognized ratably over their future service period. SFAS No. 146 is effective for termination benefits that are initiated after December 31, 2002. The Project will apply the provisions of SFAS No. 146 to all termination benefits initiated after December 31, 2002.

On January 12 2004, the FASB issued FASB Staff Position ("FSP") 106-1 *Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003.* In accordance with the FSP, the Company's post retirement benefits obligations and net periodic post retirement benefit cost in the financial statements and accompanying notes do not reflect the effects of the legislation. Specific authoritative guidance on the accounting for the legislation is pending, and that guidance, when issued, may require the Company to change previously reported information.

7. SUBSEQUENT EVENT (UNAUDITED)

On Friday February 27, 2004, AEP has signed an agreement to sell its 25.2 percent share of STPEGS to Cameco South Texas Project LP, a wholly owned U.S. subsidiary of Cameco Corp for approximately $332.6 million. The sale of AEP's share of STPEGS is subject to the right of first refusal of the co-owners. If the right of first refusal is not exercised, AEP expects the sale to close in the second half of 2004.

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