AEP Texas North Company

and Subsidiary

2007 Annual Report

Consolidated Financial Statements

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GLOSSARY OF TERMS

When the following terms and abbreviations appear in the text of this report, they have the meanings indicated below.

Term	Meaning
AEP or Parent	American Electric Power Company, Inc.
AEP East companies	APCo, CSPCo, I&M, KPCo and OPCo.
AEPEP	AEP Energy Partners, Inc., a subsidiary of AEP dedicated to wholesale marketing and trading, asset management and commercial and industrial sales in the deregulated Texas market.
AEPSC	American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries.
AEP System or the System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEP West companies	PSO, SWEPCo, TCC and TNC.
AFUDC	Allowance for Funds Used During Construction.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
ARO	Asset Retirement Obligations.
CAA	Clean Air Act.
CO_2	Carbon Dioxide.
CSPCo	Columbus Southern Power Company, an AEP electric utility subsidiary.
CSW	Central and South West Corporation, a subsidiary of AEP (Effective January 21, 2003, the legal name of Central and South West Corporation was changed to AEP Utilities, Inc.).
CSW Operating Agreement	Agreement, dated January 1, 1997, by and among PSO, SWEPCo, TCC and TNC governing generating capacity allocation. This agreement was amended in May 2006 to remove TCC and TNC. AEPSC acts as the agent.
CTC	Competition Transition Charge.
CWIP	Construction Work in Progress.
EITF	Financial Accounting Standards Board's Emerging Issues Task Force.
ERCOT	Electric Reliability Council of Texas.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FIN	FASB Interpretation No.
FIN 47	FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations."
FIN 48	FIN 48, "Accounting for Uncertainty in Income Taxes" and FASB Staff Position FIN 48-1 "Definition of *Settlement* in FASB Interpretation No. 48."
GAAP	Accounting Principles Generally Accepted in the United States of America.
IGCC	Integrated Gasification Combined Cycle, technology that turns coal into a cleaner burning gas.
IRS	Internal Revenue Service.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
kV	Kilovolt.
MTM	Mark-to-Market.
Nonutility Money Pool	AEP System's Nonutility Money Pool.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefit Plans.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.

Term	Meaning
PUCT	Public Utility Commission of Texas.
PUHCA	Public Utility Holding Company Act.
REP	Texas Retail Electric Provider.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
RTO	Regional Transmission Organization.
SEC	United States Securities and Exchange Commission.
SFAS	Statement of Financial Accounting Standards issued by the Financial Accounting Standards Board.
SFAS 71	Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation."
SFAS 109	Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes."
SFAS 133	Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities."
SFAS 143	Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations."
SFAS 157	Statement of Financial Accounting Standards No. 157, "Fair Value Measurements."
SFAS 158	Statement of Financial Accounting Standards No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans."
SFAS 159	Statement of Financial Accounting Standards No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities."
SIA	System Integration Agreement.
SPP	Southwest Power Pool.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
Texas Restructuring Legislation	Legislation enacted in 1999 to restructure the electric utility industry in Texas.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
Utility Money Pool	AEP System's Utility Money Pool.

INDEPENDENT AUDITORS' REPORT

To the Board of Directors and Shareholders of
AEP Texas North Company:

We have audited the accompanying consolidated balance sheets of AEP Texas North Company and subsidiary (the "Company") as of December 31, 2007 and 2006, and the related consolidated statements of income, changes in common shareholder's equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2007. 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 generally accepted auditing standards as established by the Auditing Standards Board (United States) and in accordance with the auditing standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, 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 AEP Texas North Company and subsidiary as of December 31, 2007 and 2006, and the results of their operations and their cash flows for the years then ended 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 FASB Interpretation No. 48, “Accounting for Uncertainty in Income Taxes”, effective January 1, 2007. As discussed in Note 7 to the consolidated financial statements, the Company adopted FASB Statement No. 158, “Employers’ Accounting for Defined Benefit Pension and Other Postretirement Plans,” effective December 31, 2006. As discussed in Note 14 to the consolidated financial statements, the Company adopted FASB Interpretation No. 47, “Accounting for Conditional Asset Retirement Obligations,” effective December 31, 2005.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 28, 2008

AEP TEXAS NORTH COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2007, 2006 and 2005
(in thousands)

	2007	2006	2005
REVENUES			
Electric Generation, Transmission and Distribution	$ 178,763	$ 295,930	$ 369,954
Sales to AEP Affiliates	96,397	33,225	47,164
Other	5,065	315	41,770
TOTAL	280,225	329,470	458,888
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	37,172	46,710	47,582
Purchased Electricity for Resale	8,059	78,708	125,590
Other Operation	77,928	81,437	120,618
Maintenance	21,308	21,846	23,636
Depreciation and Amortization	41,335	42,914	41,466
Taxes Other Than Income Taxes	20,421	22,568	23,297
TOTAL	206,223	294,183	382,189
OPERATING INCOME	74,002	35,287	76,699
Other Income (Expense):			
Interest Income	1,262	643	2,447
Allowance for Equity Funds Used During Construction	265	886	724
Interest Expense	(16,088)	(17,619)	(19,817)
INCOME BEFORE INCOME TAXES	59,441	19,197	60,053
Income Tax Expense	20,092	4,254	18,577
INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE	39,349	14,943	41,476
CUMULATIVE EFFECT OF ACCOUNTING CHANGE, NET OF TAX	-	-	(8,472)
NET INCOME	39,349	14,943	33,004
Preferred Stock Dividend Requirements	103	103	104
Gain on Reacquired Preferred Stock	-	2	-
EARNINGS APPLICABLE TO COMMON STOCK	$ 39,246	$ 14,842	$ 32,900

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

See Notes to Consolidated Financial Statements.

AEP TEXAS NORTH COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2007, 2006 and 2005
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2004	$ 137,214	$ 2,351	$ 170,984	$ (128)	$ 310,421
Common Stock Dividends			(29,026)		(29,026)
Preferred Stock Dividends			(104)		(104)
TOTAL					281,291
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $213				(396)	(396)
Minimum Pension Liability, Net of Tax of $11				20	20
NET INCOME			33,004		33,004
TOTAL COMPREHENSIVE INCOME					32,628
DECEMBER 31, 2005	137,214	2,351	174,858	(504)	313,919
Common Stock Dividends			(12,750)		(12,750)
Preferred Stock Dividends			(103)		(103)
Gain on Reacquired Preferred Stock			2		2
TOTAL					301,068
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $318				(591)	(591)
Minimum Pension Liability, Net of Tax of $37				68	68
NET INCOME			14,943		14,943
TOTAL COMPREHENSIVE INCOME					14,420
Minimum Pension Liability Elimination, Net of Tax of $175				325	325
SFAS 158 Adoption, Net of Tax of $5,092				(9,457)	(9,457)
DECEMBER 31, 2006	137,214	2,351	176,950	(10,159)	306,356
FIN 48 Adoption, Net of Tax			(557)		(557)
Common Stock Dividends			(14,000)		(14,000)
Preferred Stock Dividends			(103)		(103)
TOTAL					291,696
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $378				702	702
Pension and OPEB Funded Status, Net of Tax of $79				148	148
NET INCOME			39,349		39,349
TOTAL COMPREHENSIVE INCOME					40,199
DECEMBER 31, 2007	$ 137,214	$ 2,351	$ 201,639	$ (9,309)	$ 331,895

See Notes to Consolidated Financial Statements.

AEP TEXAS NORTH COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2007 and 2006
(in thousands)

	2007	2006
CURRENT ASSETS		
Cash and Cash Equivalents	$ -	$ 84
Other Cash Deposits	5	8,863
Advances to Affiliates	-	13,543
Accounts Receivable:		
Customers	10,255	21,677
Affiliated Companies	37,999	5,634
Accrued Unbilled Revenues	4,053	2,292
Miscellaneous	47	65
Allowance for Uncollectible Accounts	(25)	(9)
Total Accounts Receivable	52,329	29,659
Fuel	11,575	8,559
Materials and Supplies	9,994	9,319
Prepayments and Other	5,529	1,681
TOTAL	79,432	71,708
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	292,109	290,485
Transmission	344,339	327,845
Distribution	523,248	512,265
Other	160,494	159,451
Construction Work in Progress	66,761	38,847
Total	1,386,951	1,328,893
Accumulated Depreciation and Amortization	498,590	486,961
TOTAL - NET	888,361	841,932
OTHER NONCURRENT ASSETS		
Regulatory Assets	36,536	38,402
Deferred Charges and Other	18,160	15,472
TOTAL	54,696	53,874
TOTAL ASSETS	$ 1,022,489	$ 967,514

See Notes Consolidated Financial Statements.

AEP TEXAS NORTH COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
December 31, 2007 and 2006

	2007	2006
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 33,511	$ -
Accounts Payable:		
General	11,651	4,448
Affiliated Companies	46,855	43,993
Long-term Debt Due Within One Year – Nonaffiliated	-	8,151
Accrued Taxes	18,941	21,782
Other	13,712	14,934
TOTAL	124,670	93,308
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	268,875	268,785
Long-term Risk Management Liabilities	-	1,081
Deferred Income Taxes	126,667	124,048
Regulatory Liabilities and Deferred Investment Tax Credits	128,139	139,429
Deferred Credits and Other	39,894	32,158
TOTAL	563,575	565,501
TOTAL LIABILITIES	688,245	658,809
Cumulative Preferred Stock Not Subject to Mandatory Redemption	2,349	2,349
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $25 Per Share:		
Authorized – 7,800,000 Shares		
Outstanding – 5,488,560 Shares	137,214	137,214
Paid-in Capital	2,351	2,351
Retained Earnings	201,639	176,950
Accumulated Other Comprehensive Income (Loss)	(9,309)	(10,159)
TOTAL	331,895	306,356
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 1,022,489	$ 967,514

See Notes to Consolidated Financial Statements.

AEP TEXAS NORTH COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2007, 2006 and 2005
(in thousands)

	2007	2006	2005
OPERATING ACTIVITIES			
Net Income	$ 39,349	$ 14,943	$ 33,004
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	41,335	42,914	41,466
Deferred Income Taxes	(737)	(227)	(4,578)
Cumulative Effect of Accounting Change, Net of Tax	-	-	8,472
Allowance for Equity Funds Used During Construction	(265)	(886)	(724)
Mark-to-Market of Risk Management Contracts	-	2,698	1,494
Pension Contributions to Qualified Plan Trusts	-	-	(1,409)
Fuel Over/Under Recovery, Net	(7,777)	2,915	996
Change in Other Noncurrent Assets	(3,562)	(6,250)	(2,279)
Change in Other Noncurrent Liabilities	(4,016)	(7,812)	(1,897)
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	(22,670)	79,166	(2,513)
Fuel, Materials and Supplies	(3,691)	(8,384)	1,927
Accounts Payable	4,111	(54,379)	35,659
Accrued Taxes, Net	(838)	570	(16,057)
Unbilled Construction Costs	-	37	20,744
Other Current Assets	187	2,053	(99)
Other Current Liabilities	(563)	(5,943)	5,138
Net Cash Flows from Operating Activities	40,863	61,415	119,344
INVESTING ACTIVITIES			
Construction Expenditures	(88,048)	(70,350)	(63,014)
Change in Other Cash Deposits, Net	8,858	1,203	876
Change in Advances to Affiliates, Net	13,543	20,743	17,218
Proceeds from Sale of Assets	14,596	330	1,033
Other	-	-	(8,469)
Net Cash Flows Used for Investing Activities	(51,051)	(48,074)	(52,356)
FINANCING ACTIVITIES			
Issuance of Long-term Debt – Nonaffiliated	43,681	-	-
Change in Advances from Affiliates, Net	33,511	-	-
Retirement of Long-term Debt - Nonaffiliated	(52,461)	-	(37,609)
Retirement of Cumulative Preferred Stock	-	(6)	-
Principal Payments for Capital Lease Obligations	(524)	(398)	(249)
Dividends Paid on Common Stock	(14,000)	(12,750)	(29,026)
Dividends Paid on Cumulative Preferred Stock	(103)	(103)	(104)
Net Cash Flows from (Used for) Financing Activities	10,104	(13,257)	(66,988)
Net Increase (Decrease) in Cash and Cash Equivalents	(84)	84	-
Cash and Cash Equivalents at Beginning of Period	84	-	-
Cash and Cash Equivalents at End of Period	$ -	$ 84	$ -
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 15,589	$ 15,457	$ 19,042
Net Cash Paid for Income Taxes	20,698	5,834	41,306
Noncash Acquisitions Under Capital Leases	202	1,291	442
Construction Expenditures Included in Accounts Payable at December 31,	7,271	1,317	3,159

See Notes to Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization and Summary of Significant Accounting Policies
2. New Accounting Pronouncements and Cumulative Effect of Accounting Change
3. Rate Matters
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1. <u>ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES</u>

ORGANIZATION

As a public utility, TNC engages in the transmission and distribution of electric power to 184,000 retail customers through REPs in its service territory in western and central Texas.

Under the Texas Restructuring Legislation, TNC completed the final stage of exiting the generation business and ceased serving retail load. Based on the corporate separation and generation divestiture, the nature of TNC business is no longer compatible with its participation in the CSW Operating Agreement and the SIA since these agreements involve the coordinated planning and operation of power supply facilities. Accordingly, TNC sought and received FERC approval to be removed from those agreements. TNC's sharing of margins under the CSW Operating Agreement ceased on May 1, 2006. The sharing of margins with AEP East companies under the SIA ceased on April 1, 2006. These trading and marketing margins affected TNC's results of operations and cash flows.

Prior to May 1, 2006, as a member of the CSW Operating Agreement, TNC was compensated for energy delivered to other members based upon its incremental cost plus a portion of the savings realized by the purchasing member that avoids the use of more costly alternatives. The revenues and costs for sales to neighboring utilities and power marketers made by AEPSC on behalf of the AEP West companies were generally shared among the members based upon the relative magnitude of energy each member provided to make such sales.

Prior to April 1, 2006, under the SIA, revenues and expenses from the sales to neighboring utilities, power marketers and other power and gas risk management activities were shared among AEP East companies and AEP West companies. Sharing in a calendar year was 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 companies' and AEP 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 companies and AEP West companies in the event the pre-merger activity level was exceeded. The capacity-based allocation mechanism was triggered in July 2005, resulting in an allocation factor of approximately 70% and 30% for the AEP East companies and AEP West companies, respectively, for the remainder of the year.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

TNC is regulated by the FERC under the 2005 Public Utility Holding Company Act (2005 PUHCA) and by the PUCT. The PUCT approves the rates TNC charges and regulates the services and operations for a majority of TNC's transmission and distribution energy delivery services. The FERC regulates certain, mostly affiliated, transactions under the 2005 PUHCA.

The FERC regulates wholesale power markets and wholesale power transactions. Prior to January 1, 2007, TNC's wholesale power transactions were generally market-based and not cost-based regulated unless TNC negotiated and filed a cost-based contract with the FERC or the FERC determined that TNC had "market power" in the region in which the transaction was taking place. Prior to January 1, 2007, TNC entered into wholesale power supply contracts with various municipalities and cooperatives that were FERC regulated, market-based contracts. TNC wholesale power transactions in the SPP region were all cost-based due to TNC having market power in the SPP region. Effective January 1, 2007, all of TNC's supply contacts were assigned to AEP Energy Partners.

Generally, the FERC also regulates, on a cost basis, wholesale transmission service and rates. TNC's wholesale transmission rates are also regulated on a cost basis by the PUCT. TNC offers no retail transmission service.

In addition, the FERC regulates the CSW Operating Agreement, the Transmission Coordination Agreement, and the SIA, all of which allocate shared system costs and revenues to the utility subsidiaries that are parties to the agreements, including TNC. The sharing of margins with the AEP East companies under the SIA ceased on April 1, 2006.

The PUCT regulates all of TNC's public utility operations where transmission and distribution rates are regulated on a cost-basis and unbundled by function. TNC has no Texas jurisdictional retail generation/power supply operations.

In 2005, TNC was subject to regulation by the SEC under the Public Utility Holding Company Act of 1935 (1935 PUHCA). The Energy Policy Act of 2005 repealed the 1935 PUHCA effective February 8, 2006 and replaced it with the 2005 PUHCA. With the repeal of the 1935 PUHCA, the SEC no longer has jurisdiction over the activities of registered holding companies, their respective service corporations and their intercompany transactions, which it regulated predominantly at cost. Jurisdiction over holding company-related activities was transferred to the FERC and the required reporting was reduced by the 2005 PUHCA. The FERC also has jurisdiction over the issuances and acquisitions of securities of the public utility subsidiaries, the acquisition or sale of certain utility assets, mergers with another electric utility or holding company, inter-company transactions, accounting and AEPSC intercompany service billings which are generally at cost. The intercompany sale of non-power goods and non-AEPSC services to affiliates cannot exceed market under the 2005 PUHCA.

Both the FERC and the PUCT are permitted to review and audit the books and records of TNC.

Principles of Consolidation

TNC's consolidated financial statements include TNC and its wholly-owned subsidiary. Intercompany items are eliminated in consolidation. TNC also has a generating unit that is jointly-owned with an affiliated company and nonaffiliated companies. TNC's proportionate share of the operating costs associated with that facility is included in the financial statements and the assets and liabilities are reflected in the balance sheets. See "Oklaunion PPA between TNC and AEP Energy Partners" section within Note 13 for detail of TNC's agreement to sell its portion of the Oklaunion generation to AEPEP.

Accounting for the Effects of Cost-Based Regulation

As a cost-based rate-regulated electric transmission and distribution company, TNC's financial statements reflect the actions of regulators that result in the recognition of certain revenues and expenses in different time periods than enterprises that are not rate-regulated. In accordance with SFAS 71, 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 and income with its passage to customers through the reduction of regulated revenues. Due to the commencement of legislatively required restructuring and a transition to customer choice and market-based rates, TNC discontinued the application of SFAS 71, regulatory accounting, for the generation portion of its business in September 1999.

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, long-lived asset impairment, unbilled electricity revenue, valuation 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 and postretirement benefits. The estimates and assumptions used are based upon management's evaluation of the relevant facts and circumstances as of the date of the financial statements. Actual results could ultimately differ from those estimates.

Property, Plant and Equipment and Equity Investments

Electric utility property, plant and equipment are stated at original purchase cost. Property, plant and equipment of nonregulated operations and other investments are stated at 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. Normal and routine retirements from the plant accounts, net of salvage, are charged to accumulated depreciation for both cost-based rate-regulated and nonregulated operations under the group composite method of depreciation. The group composite method of depreciation assumes that on average, asset components are retired at the end of their useful lives and thus there is no gain or loss. The equipment in each primary electric plant account is identified as a separate group. Under the group composite method of depreciation, continuous interim routine replacements of items such as boiler tubes, pumps, motors, etc. result in the original cost, less salvage, being charged to accumulated depreciation. For the nonregulated generation assets, a gain or loss would be recorded if the retirement is not considered an interim routine replacement. The depreciation rates that are established for the generating plants take into account the past history of interim capital replacements and the amount of salvage received. These rates and the related lives are subject to periodic review. Removal costs are charged to regulatory liabilities for cost-based rate-regulated operations and charged to expense for nonregulated operations. The costs of labor, materials and overhead incurred to operate and maintain the plants are included in operating expenses.

Long-lived assets are required to be tested for impairment when it is determined that the carrying value of the assets may no longer be recoverable or when the assets meet the held for sale criteria under SFAS 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." Equity investments are required to be tested for impairment when it is determined there may be an other than temporary loss in value.

The fair value of an asset or investment is the amount at which that asset or investment could be bought or sold in a current transaction between willing parties, as opposed to a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets or investments in active markets, fair value is estimated using various internal and external valuation methods including cash flow analysis and appraisals.

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 nonregulated operations including domestic generating assets in Texas effective with the discontinuance of SFAS 71 regulatory accounting, interest is capitalized during construction in accordance with SFAS 34, "Capitalization of Interest Costs."

Valuation of Nonderivative Financial Instruments

The book values of Cash and Cash Equivalents, Other Cash Deposits, Accounts Receivable and Accounts Payable approximate fair value because of the short-term maturity of these instruments.

Cash and Cash Equivalents

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

Other Cash Deposits

Other Cash Deposits include funds held by trustees primarily for the payment of debt.

Inventory

Fossil fuel inventories are carried at the lower of cost or market using a LIFO method. Materials and supplies inventories are carried at average cost.

Accounts Receivable

Customer accounts receivable primarily include receivables from wholesale and retail energy customers and customer receivables primarily related to other revenue-generating activities.

Revenue is recognized from electric power sales or delivery when power is delivered to customers. To the extent that deliveries have occurred but a bill has not been issued, TNC accrues and recognizes, as Accrued Unbilled Revenues, an estimate of the revenues for energy delivered since the last billing.

Concentrations of Credit Risk and Significant Customers

TNC has significant customers which on a combined basis account for the following percentages of total Operating Revenues for the periods ended and Accounts Receivable – Customers as of December 31:

	2007	2006	2005
TNC – Centrica, ERCOT (2006 and 2005 only) and City of College Station (2006 only)			
Percentage of Operating Revenues	15%	50%	27%
Percentage of Accounts Receivable - Customers	36%	38%	12%

TNC monitors credit levels and the financial condition of their customers on a continuing basis to minimize credit risk. Management believes adequate provision for credit loss has been made in the accompanying financial statements.

Revenue Recognition

Regulatory Accounting

The financial statements for cost-based rate-regulated operations 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. 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 in cost-based regulated rates.

When regulatory assets are probable of recovery through regulated rates, TNC records them as assets on the balance sheet. TNC tests for probability of recovery whenever new events occur, for example, issuance of a regulatory commission order or passage of new legislation. If it is determined that recovery of a regulatory asset is no longer probable, TNC writes off that regulatory asset as a charge against earnings.

Traditional Electricity Supply and Delivery Activities

TNC recognizes revenues from wholesale electricity supply sales and electricity transmission and distribution delivery services. TNC recognizes the revenues in the financial statements upon delivery of the energy to the customer and includes unbilled as well as billed amounts. TNC records expenses upon receipt of purchased electricity and when expenses are incurred. TNC records third party purchases as non-trading and these purchases are accounted for on a gross basis as Purchased Electricity for Resale in the Consolidated Statements of Income.

Energy Marketing and Risk Management Activities

Prior to the FERC approved removal from the SIA and CSW Operating Agreement, effective April 1, and May 1, 2006 respectively, TNC engaged in wholesale electricity, natural gas, coal and emission allowances marketing and risk management activities focused on wholesale markets where the AEP System owns assets. TNC's activities included the purchase and sale of energy under forward contracts at fixed and variable prices and the buying and selling of financial energy contracts which included exchange traded futures and options, and over-the-counter options and swaps. TNC engaged in certain energy marketing and risk management transactions with RTOs.

TNC recognized revenues and expenses from wholesale marketing and risk management transactions that were not derivatives upon delivery of the commodity. TNC used MTM accounting for wholesale marketing and risk management transactions that were derivatives unless the derivative was designated in a qualifying cash flow hedge relationship or as a normal purchase or sale. TNC recorded the unrealized and realized gains and losses on wholesale marketing and risk management transactions accounted for using MTM in Revenues in the Consolidated Statements of Income on a net basis.

Certain qualifying wholesale marketing and risk management derivative transactions were designated as hedges of future cash flows as a result of forecasted transactions (cash flow hedge). TNC initially recorded the effective portion of the cash flow hedge's gain or loss as a component of Accumulated Other Comprehensive Income (Loss). When the forecasted transaction was realized and affected earnings, TNC subsequently reclassified the gain or loss on the hedge from Accumulated Other Comprehensive Income into revenues or expenses on its Consolidated Statements of Income, within the same financial statement line item as the forecasted transaction. The ineffective portion of the gain or loss was recognized in revenues in the financial statements immediately.

Construction Projects for Outside Parties

TNC engages in construction projects for outside parties that are accounted for on the percentage-of-completion method of revenue recognition. This method recognizes revenue, including the related margin, as project costs are incurred. TNC includes such revenue and related expenses in Other Revenue and Other Operation Expenses, respectively, in the financial statements. TNC includes contractually billable expenses not yet billed in Current Assets in the financial statements.

Power Purchase and Sale Agreement

TNC recognizes revenue from an affiliate, AEP Energy Partners (AEPEP), for a 20-year Power Purchase & Sale Agreement (PPA). TNC recognizes revenues for the fuel, operations and maintenance and all other taxes on a billed basis. Revenue is recognized for the capacity and depreciation billed to AEPEP on a straight-line basis over the term of the PPA as these represent the minimum payments due.

Maintenance

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

Income Taxes and Investment Tax Credits

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

When 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 are accounted for under the deferral basis and are being amortized over the life of the plant investment.

TNC accounts for uncertain tax positions in accordance with FIN 48. Effective with the adoption of FIN 48, TNC classifies interest expense or income related to uncertain tax positions as interest expense or income as appropriate and classifies penalties as Other Operation.

Excise Taxes

As an agent for some state and local governments, TNC collects from customers certain excise taxes levied by those state or local governments on customers. TNC does not record these taxes as revenue or expense.

Debt and Preferred Stock

Gains and losses from the reacquisition of debt used to finance regulated electric utility plants are 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.

Debt discount or premium and debt issuance expenses are deferred and amortized generally utilizing the straight-line method over the term of the related debt. The straight-line method approximates the effective interest method and is consistent with the treatment in rates for regulated operations. The net amortization expense is included in Interest Expense.

The excess of par value over costs of preferred stock reacquired is credited to paid-in capital and reclassified to retained earnings upon the redemption of the entire preferred stock series. The excess of par value over the costs of reacquired preferred stock for nonregulated subsidiaries is credited to retained earnings upon reacquisition.

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 nonowner 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).

Components of Accumulated Other Comprehensive Income (Loss) (AOCI)

AOCI is included on the balance sheets in the common shareholder's equity section. AOCI for TNC as of December 31, 2007 and 2006 is shown in the following table.

	December 31,	
	2007	2006
Components	(in thousands)	
Cash Flow Hedges	$ -	$ (702)
Pension and OPEB Funded Status	(9,309)	(9,457)

Earnings Per Share (EPS)

TNC is owned by a wholly-owned subsidiary of AEP. Therefore, TNC is not required to report EPS.

Reclassifications

Certain prior period financial statement items have been reclassified to conform to current period presentation. These revisions had no impact on TNC's previously reported results of operations or changes in shareholders' equity.

2. NEW ACCOUNTING PRONOUNCEMENTS AND CUMULATIVE EFFECT OF ACCOUNTING CHANGE

NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of exposure drafts or final pronouncements, management thoroughly reviews the new accounting literature to determine the relevance, if any, to TNC's business. The following represents a summary of final pronouncements that management has determined relate to TNC's operations.

SFAS 141 (revised 2007) "Business Combinations" (SFAS 141R)

In December 2007, the FASB issued SFAS 141R, improving financial reporting about business combinations and their effects. It establishes how the acquiring entity recognizes and measures the identifiable assets acquired, liabilities assumed, goodwill acquired, any gain on bargain purchases and any noncontrolling interest in the acquired entity. SFAS 141R no longer allows acquisition-related costs to be included in the cost of the business combination, but rather expensed in the periods they are incurred, with the exception of the costs to issue debt or equity securities which shall be recognized in accordance with other applicable GAAP. SFAS 141R requires disclosure of information for a business combination that occurs during the accounting period or prior to the issuance of the financial statements for the accounting period.

SFAS 141R is effective prospectively for business combinations with an acquisition date on or after the beginning of the first annual reporting period after December 15, 2008. Early adoption is prohibited. TNC will adopt SFAS 141R effective January 1, 2009 and apply it to any business combinations on or after that date.

SFAS 157 "Fair Value Measurements" (SFAS 157)

In September 2006, the FASB issued SFAS 157, enhancing existing guidance for fair value measurement of assets and liabilities and instruments measured at fair value that are classified in shareholders' equity. The statement defines fair value, establishes a fair value measurement framework and expands fair value disclosures. It emphasizes that fair value is market-based with the highest measurement hierarchy level being market prices in active markets. The standard requires fair value measurements be disclosed by hierarchy level, an entity include its own credit standing in the measurement of its liabilities and modifies the transaction price presumption. The standard also nullifies the consensus reached in EITF Issue No. 02-3 "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities" (EITF 02-3) that prohibited the recognition of trading gains or losses at the inception of a derivative contract, unless the fair value of such derivative is supported by observable market data.

In February 2008, the FASB issued FASB Staff Position (FSP) FAS 157-1 "Application of FASB Statement No. 157 to FASB Statement No. 13 and Other Accounting Pronouncements That Address Fair Value Measurements for Purposes of Lease Classification or Measurement under Statement 13" which amends SFAS 157 to exclude SFAS 13 "Accounting for Leases" and other accounting pronouncements that address fair value measurements for purposes of lease classification or measurement under SFAS 13.

In February 2008, the FASB issued FSP FAS 157-2 "Effective Date of FASB Statement No. 157" which delays the effective date of SFAS 157 to fiscal years beginning after November 15, 2008 for all nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually).

TNC partially adopted SFAS 157 effective January 1, 2008. TNC will adopt SFAS 157 effective January 1, 2009 for items within the scope of FSP FAS 157-2. The provisions of SFAS 157 are applied prospectively, except for a) changes in fair value measurements of existing derivative financial instruments measured initially using the transaction price under EITF 02-3, b) existing hybrid financial instruments measured initially at fair value using the transaction price and c) blockage discount factors. Although the statement is applied prospectively upon adoption, in accordance with the provisions of SFAS 157 related to EITF 02-3, amounts for transition adjustment are recorded to beginning retained earnings. The consideration of AEP's own credit risk when measuring the fair value of liabilities, including derivatives, impacts fair value measurements upon adoption. The adoption of this standard had no impact on TNC's financial statements.

SFAS 159 "The Fair Value Option for Financial Assets and Financial Liabilities" (SFAS 159)

In February 2007, the FASB issued SFAS 159, permitting entities to choose to measure many financial instruments and certain other items at fair value. The standard also establishes presentation and disclosure requirements designed to facilitate comparison between entities that choose different measurement attributes for similar types of assets and liabilities. If the fair value option is elected, the effect of the first remeasurement to fair value is reported as a cumulative effect adjustment to the opening balance of retained earnings. The statement is applied prospectively upon adoption.

TNC adopted SFAS 159 effective January 1, 2008. At adoption, TNC did not elect the fair value option for any assets or liabilities.

SFAS 160 "Noncontrolling Interest in Consolidated Financial Statements" (SFAS 160)

In December 2007, the FASB issued SFAS 160, modifying reporting for noncontrolling interest (minority interest) in consolidated financial statements. It requires noncontrolling interest be reported in equity and establishes a new framework for recognizing net income or loss and comprehensive income by the controlling interest. Upon deconsolidation due to loss of control over a subsidiary, the standard requires a fair value remeasurement of any remaining noncontrolling equity investment to be used to properly recognize the gain or loss. SFAS 160 requires specific disclosures regarding changes in equity interest of both the controlling and noncontrolling parties and presentation of the noncontrolling equity balance and income or loss for all periods presented.

SFAS 160 is effective for interim and annual periods in fiscal years beginning after December 15, 2008. The statement is applied prospectively upon adoption. Early adoption is prohibited. Upon adoption, prior period financial statements will be restated for the presentation of the noncontrolling interest for comparability. Although management has not completed its analysis, management expects that the adoption of this standard will have an immaterial impact on the financial statements. TNC will adopt SFAS 160 effective January 1, 2009.

EITF Issue No. 06-10 "Accounting for Collateral Assignment Split-Dollar Life Insurance Arrangements" (EITF 06-10)

In March 2007, the FASB ratified EITF 06-10, a consensus on collateral assignment split-dollar life insurance arrangements in which an employee owns and controls the insurance policy. Under EITF 06-10, an employer should recognize a liability for the postretirement benefit related to a collateral assignment split-dollar life insurance arrangement in accordance with SFAS 106 "Employers' Accounting for Postretirement Benefits Other Than Pension" or Accounting Principles Board Opinion No. 12 "Omnibus Opinion – 1967" if the employer has agreed to maintain a life insurance policy during the employee's retirement or to provide the employee with a death benefit based on a substantive arrangement with the employee. In addition, an employer should recognize and measure an asset based on the nature and substance of the collateral assignment split-dollar life insurance arrangement. EITF 06-10 requires recognition of the effects of its application as either (a) a change in accounting principle through a cumulative effect adjustment to retained earnings or other components of equity or net assets in the statement of financial position at the beginning of the year of adoption or (b) a change in accounting principle through retrospective application to all prior periods. TNC adopted EITF 06-10 effective January 1, 2008 with an immaterial effect on the financial statements.

EITF Issue No. 06-11 "Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards" (EITF 06-11)

In June 2007, the FASB ratified the EITF consensus on the treatment of income tax benefits of dividends on employee share-based compensation. The issue is how a company should recognize the income tax benefit received on dividends that are paid to employees holding equity-classified nonvested shares, equity-classified nonvested share units or equity-classified outstanding share options and charged to retained earnings under SFAS 123R, "Share-Based Payments." Under EITF 06-11, a realized income tax benefit from dividends or dividend equivalents that are charged to retained earnings and are paid to employees for equity-classified nonvested equity shares, nonvested equity share units and outstanding equity share options should be recognized as an increase to additional paid-in capital.

TNC adopted EITF 06-11 effective January 1, 2008. EITF 06-11 is applied prospectively to the income tax benefits of dividends on equity-classified employee share-based payment awards that are declared in fiscal years after September 15, 2007. The adoption of this standard had an immaterial impact on the financial statements.

FIN 48 "Accounting for Uncertainty in Income Taxes" and FASB Staff Position FIN 48-1 "Definition of Settlement in FASB Interpretation No. 48" (FIN 48)

In July 2006, the FASB issued FASB Interpretation No. 48 "Accounting for Uncertainty in Income Taxes" and in May 2007, the FASB issued FASB Staff Position FIN 48-1 "Definition of *Settlement* in FASB Interpretation No. 48." FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements by prescribing a recognition threshold (whether a tax position is more likely than not to be sustained) without which, the benefit of that position is not recognized in the financial statements. It requires a measurement determination for recognized tax positions based on the largest amount of benefit that is greater than 50 percent likely of being realized upon ultimate settlement. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition.

FIN 48 requires that the cumulative effect of applying this interpretation be reported and disclosed as an adjustment to the opening balance of retained earnings for that fiscal year and presented separately. TNC adopted FIN 48 effective January 1, 2007. The impact of this interpretation was an unfavorable adjustment to retained earnings of $557 thousand.

FIN 39-1 "Amendment of FASB Interpretation No. 39" (FIN 39-1)

In April 2007, the FASB issued FIN 39-1. It amends FASB Interpretation No. 39, "Offsetting of Amounts Related to Certain Contracts" by replacing the interpretation's definition of contracts with the definition of derivative instruments per SFAS 133. It also requires entities that offset fair values of derivatives with the same party under a netting agreement to also net the fair values (or approximate fair values) of related cash collateral. The entities must disclose whether or not they offset fair values of derivatives and related cash collateral and amounts recognized for cash collateral payables and receivables at the end of each reporting period.

TNC adopted FIN 39-1 effective January 1, 2008. This standard changed the method of netting certain balance sheet amounts. It requires retrospective application as a change in accounting principle for all periods presented. It had no impact on TNC.

Future Accounting Changes

The FASB's standard-setting process is ongoing and until new standards have been finalized and issued by the FASB, management cannot determine the impact on the reporting of operations and financial position that may result from any such future changes. The FASB is currently working on several projects including revenue recognition, liabilities and equity, derivatives disclosures, emission allowances, leases, insurance, subsequent events and related tax impacts. Management also expects to see more FASB projects as a result of its desire to converge International Accounting Standards with GAAP. The ultimate pronouncements resulting from these and future projects could have an impact on future results of operations and financial position.

CUMULATIVE EFFECT OF ACCOUNTING CHANGE

Asset Retirement Obligations

In 2005, TNC recorded a $13 million ($8.5 million net of tax) loss as a cumulative effect of accounting change for ARO in accordance with FIN 47.

3. RATE MATTERS

TNC is involved in rate and regulatory proceedings at the FERC and the PUCT. This note is a discussion of rate matters and industry restructuring related proceedings that could have a material effect on the results of operations and cash flows.

Deferred Fuel

TNC and the PUCT have been involved in litigation in the federal courts concerning whether the PUCT has the right to order reallocation of off-system sales margins thereby reducing recoverable fuel costs. In 2005, TNC recorded a provision for refund after the PUCT ordered such reallocation. After receipt of favorable federal court decisions and the refusal of the Supreme Court of the United States to hear a PUCT appeal, TNC reversed its provision of $9 million in the third quarter of 2007.

The PUCT or another interested party could file a complaint at the FERC to challenge the allocation of off-system sales margins under the FERC-approved allocation agreement. In December 2007, some cities served by TNC requested the PUCT to initiate, or order TNC to initiate a proceeding at the FERC to determine if TNC misapplied its tariff. In January 2008, TNC filed a response with the PUCT recommending the cities' request be denied. Although management cannot predict if a complaint will be filed at the FERC, management believes the allocations were in accordance with the then-existing FERC-approved allocation agreement and additional off-system sales margins should not be retroactively reallocated to the AEP West companies including TNC.

Energy Delivery Base Rate Filing

TNC filed a base rate case seeking to increase transmission and distribution energy delivery services (wires) base rates in Texas. TNC's revised requested increase in annual base rates was $22 million based on a requested return on common equity of 10.75%.

In May 2007, the PUCT approved a settlement agreement for TNC, which resulted in an $8 million increase in base rates, a $6 million increase related to the impact of the expiration of the merger credits and a return on common equity of 9.96%. TNC estimates the settlement will increase annual revenues by $14 million. TNC began billing the increased rates in June 2007.

4. EFFECTS OF REGULATION

Regulatory Assets and Liabilities

Regulatory assets and liabilities are comprised of the following items:

	December 31, 2007	December 31, 2006	Notes
	(in thousands)		
Regulatory Assets:			
SFAS 158 Regulatory Asset (Note 7)	$ 25,867	$ 29,334	(a) (e)
Unamortized Loss on Reacquired Debt	6,399	6,036	(b) (g)
Other	4,270	3,032	(c) (e)
Total Noncurrent Regulatory Assets	$ 36,536	$ 38,402	
Regulatory Liabilities:			
Asset Removal Costs (Note 14)	$ 92,151	$ 87,313	(d)
Deferred Investment Tax Credits	15,039	16,157	(a) (f)
SFAS 109 Regulatory Liability, Net (Note 10)	8,694	9,689	(b) (e)
CTC Refund	-	12,865	(b)
Other	12,255	13,405	(c) (e)
Total Noncurrent Regulatory Liabilities	$ 128,139	$ 139,429	

(a) Amount does not earn a return.
(b) Amount effectively earns a return.
(c) Includes items both earning and not earning a return.
(d) The liability for removal costs, which reduces rate base and the resultant return, will be discharged as removal costs are incurred.
(e) Recovery/refund period – various periods.
(f) Recovery/refund period – up to 55 years.
(g) Recovery/refund period – up to 13 years.

5. COMMITMENTS, GUARANTEES AND CONTINGENCIES

TNC is subject to certain claims and legal actions arising in its ordinary course of business. In addition, TNC's business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation cannot be predicted. For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material adverse effect on the financial statements.

Insurance and Potential Losses

TNC maintains insurance coverage normal and customary for an electric utility, subject to various deductibles. The insurance includes coverage for all risks of physical loss or damage to assets, subject to insurance policy conditions and exclusions. Covered property generally includes substations, facilities and inventories. Excluded property generally includes transmission and distribution lines, poles and towers. TNC's insurance programs also generally provide coverage against loss arising from certain claims made by third parties and are in excess of TNC's retentions. Coverage is generally provided by a combination of a South Carolina domiciled protected-cell captive insurance company together with and/or in addition to various industry mutual and commercial insurance carriers.

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. Future losses or liabilities, if they occur, which are not completely insured, unless recovered from customers, could have a material adverse effect on results of operations, cash flows and financial condition.

COMMITMENTS

TNC has substantial construction commitments to support its operations and environmental investments. In managing the overall construction program and in the normal course of business, TNC contractually commits to third-party construction vendors for certain material purchases and other construction services. Aggregate construction expenditures for 2008 through 2010 are estimated at approximately $421.7 million. The amounts for 2008, 2009 and 2010 are $120 million, $155.8 million and $145.9 million, respectively. Estimated construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, weather, legal reviews and the ability to access capital.

TNC purchases materials, supplies, services and property, plant and equipment under contract as part of its normal course of business. Certain supply contracts contain penalty provisions for early termination. TNC does not expect to incur penalty payments under these provisions that would materially affect results of operations, cash flows or financial condition.

GUARANTEES

There are certain immaterial liabilities recorded for guarantees in accordance with FIN 45 "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others." There is no collateral held in relation to any guarantees. In the event any guarantee is drawn, there is no recourse to third parties.

Indemnifications and Other Guarantees

<u>*Contracts*</u>

TNC enters into certain types of contracts which 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. Prior to December 31, 2007, TNC entered into sale agreements including indemnifications with a maximum exposure that was not significant. There are no material liabilities recorded for any indemnifications.

<u>*Master Operating Lease*</u>

TNC leases 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, TNC has 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. Historically, at the end of the lease term the fair market value has been in excess of the unamortized balance. Assuming the fair market value of the equipment is zero at the end of the lease term, the maximum potential loss for these lease agreements was approximately $3 million as of December 31, 2007.

CONTINGENCIES

Carbon Dioxide (CO_2) Public Nuisance Claims

In 2004, eight states and the City of New York filed an action in federal district court for the Southern District of New York against AEP, AEPSC, Cinergy Corp, Xcel Energy, Southern Company and Tennessee Valley Authority. The Natural Resources Defense Council, on behalf of three special interest groups, filed a similar complaint against the same defendants. The actions allege that CO_2 emissions from the defendants' power plants constitute a public nuisance under federal common law due to impacts of global warming, and sought injunctive relief in the form of specific emission reduction commitments from the defendants. The dismissal of the lawsuit was appealed to the Second Circuit Court of Appeals. Briefing and oral argument have concluded. In April 2007, the U.S. Supreme Court issued a decision holding that the Federal EPA has authority to regulate emissions of CO_2 and other greenhouse gases under the CAA, which may impact the Second Circuit's analysis of these issues. The Second Circuit requested supplemental briefs addressing the impact of the Supreme Court's decision on this case. Management believes the actions are without merit and intends to defend against the claims.

The Comprehensive Environmental Response Compensation and Liability Act (Superfund) and State Remediation

By-products from the generation of electricity include materials such as ash, slag and sludge. Coal combustion by-products, which constitute the overwhelming percentage of these materials, are typically treated and deposited in captive disposal facilities or are beneficially utilized. In addition, the generating plants and transmission and distribution facilities have used asbestos, polychlorinated biphenyls (PCBs) and other hazardous and nonhazardous materials. TNC currently incur costs to safely dispose of these substances.

Superfund addresses clean-up of hazardous substances that have been released to the environment. The Federal EPA administers the clean-up programs. Several states have enacted similar laws. At December 31, 2007, TNC has been named potentially liable at one site under state law. In the instance where TNC has been named a defendant, disposal or recycling activities were in accordance with the then-applicable laws and regulations. Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories. Liability has been resolved for a number of sites with no significant effect on results of operations.

TNC evaluates the potential liability for each site separately, but several general statements can be made regarding potential future liability. Disposal of materials 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 for each site and several of the parties are financially sound enterprises. At present, management's estimates do not anticipate material cleanup costs for identified sites.

Coal Transportation Dispute

PSO, TCC, TNC, the Oklahoma Municipal Power Authority and the Public Utilities Board of the City of Brownsville, Texas, as joint owners of a generating station, disputed transportation costs for coal received between July 2000 and the present time. The joint plant remitted less than the amount billed. In September 2007, the Surface Transportation Board ruled that the disputed rates were not unreasonable under the standalone cost rate test. The joint owners filed a Petition for Reconsideration. Based upon this ruling, PSO, as operator of the plant, adjusted the provision recorded in prior periods. TNC made an adjustment to its provision based on its ownership share. After mitigation by certain contractual rights, TNC's fuel expense decreased by $9.4 million.

FERC Long-term Contracts

In 2002, the FERC held a hearing related to a complaint filed by Nevada Power Company and Sierra Pacific Power Company (the Nevada utilities). The complaint sought to break long-term contracts entered during the 2000 and 2001 California energy price spike which the customers alleged were "high-priced." The complaint alleged that TNC and certain other AEP subsidiaries sold power at unjust and unreasonable prices because the market for power was allegedly dysfunctional at the time such contracts were executed. In 2003, the FERC rejected the complaint. In 2006, the U.S. Court of Appeals for the Ninth Circuit reversed the FERC order and remanded the case to the FERC for further proceedings. That decision was appealed and the U.S. Supreme Court decided that it will review the Ninth

Circuit's decision in 2008. Management is unable to predict the outcome of these proceedings or their impact on future results of operations and cash flows. Management asserted claims against certain companies that sold power to TNC and certain other AEP subsidiaries, which was resold to the Nevada utilities, seeking to recover a portion of any amounts that may be owed to the Nevada utilities.

6. COMPANY-WIDE STAFFING AND BUDGET REVIEW

TNC recorded $1.3 million of severance benefits expense in 2005 (primarily in Other Operation and Maintenance) resulting from a company-wide staffing and budget review, including the allocation of approximately $19.2 million of severance benefits expense associated with AEPSC employees. Payments and accrual adjustments recorded during 2006 were immaterial and were settled by June 30, 2006.

7. BENEFIT PLANS

TNC participates in AEP sponsored 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, TNC participates in other postretirement benefit plans sponsored by AEP to provide medical and death benefits for retired employees.

TNC adopted SFAS 158 as of December 31, 2006. It requires employers to fully recognize the obligations associated with defined benefit pension plans and OPEB plans, which include retiree healthcare, in their balance sheets. Previous standards required an employer to disclose the complete funded status of its plan only in the notes to the financial statements and provided that an employer delay recognition of certain changes in plan assets and obligations that affected the costs of providing benefits resulting in an asset or liability that often differed from the plan's funded status. SFAS 158 requires a defined benefit pension or postretirement plan sponsor to (a) recognize in its statement of financial position an asset for a plan's overfunded status or a liability for the plan's underfunded status, (b) measure the plan's assets and obligations that determine its funded status as of the end of the employer's fiscal year and (c) recognize, as a component of other comprehensive income, the changes in the funded status of the plan that arise during the year but are not recognized as a component of net periodic benefit cost pursuant to previous standards. It also requires an employer to disclose additional information on how delayed recognition of certain changes in the funded status of a defined benefit pension or OPEB plan affects net periodic benefit costs for the next fiscal year. TNC recorded a SFAS 71 regulatory asset for qualifying SFAS 158 costs of regulated operations that for ratemaking purposes will be deferred for future recovery. The effect of this standard on the 2006 financial statements was a pretax AOCI adjustment of $43.9 million that was partially offset by a SFAS 71 regulatory asset of $29.3 million and a deferred income tax asset of $5.1 million resulting in a net of tax AOCI equity reduction of $9.5 million.

SFAS 158 requires adjustment of pretax AOCI at the end of each year, for both underfunded and overfunded defined benefit pension and OPEB plans, to an amount equal to the remaining unrecognized deferrals for unamortized actuarial losses or gains, prior service costs and transition obligations, such that remaining deferred costs result in an AOCI equity reduction and deferred gains result in an AOCI equity addition. The year-end AOCI measure can be volatile based on fluctuating investment returns and discount rates.

The following tables provide a reconciliation of the changes in projected benefit obligations and fair value of assets for AEP’s plans over the two-year period ending at the plan’s measurement date of December 31, 2007, and their funded status as of December 31 for each year:

Projected Pension Obligations, Plan Assets, Funded Status as of December 31, 2007 and 2006

	Pension Plans		Other Postretirement Benefit Plans	
	2007	**2006**	**2007**	**2006**
	(in millions)			
Change in Projected Benefit Obligation				
Projected Obligation at January 1	$ 4,108	$ 4,347	$ 1,818	$ 1,831
Service Cost	96	97	42	39
Interest Cost	235	231	104	102
Actuarial Gain	(64)	(293)	(91)	(55)
Plan Amendments	18	2	-	-
Benefit Payments	(284)	(276)	(130)	(112)
Participant Contributions	-	-	22	21
Medicare Subsidy	-	-	8	(8)
Projected Obligation at December 31	$ 4,109	$ 4,108	$ 1,773	$ 1,818
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets at January 1	$ 4,346	$ 4,143	$ 1,302	$ 1,172
Actual Return on Plan Assets	435	470	115	127
Company Contributions	7	9	91	94
Participant Contributions	-	-	22	21
Benefit Payments	(284)	(276)	(130)	(112)
Fair Value of Plan Assets at December 31	$ 4,504	$ 4,346	$ 1,400	$ 1,302
Funded (Underfunded) Status at December 31	$ 395	$ 238	$ (373)	$ (516)

Amounts Recognized on AEP’s Balance Sheets as of December 31, 2007 and 2006

	Pension Plans		Other Postretirement Benefit Plans	
	2007	**2006**	**2007**	**2006**
	(in millions)			
Employee Benefits and Pension Assets – Prepaid Benefit Costs	$ 482	$ 320	$ -	$ -
Other Current Liabilities – Accrued Short-term Benefit Liability	(8)	(8)	(4)	(5)
Employee Benefits and Pension Obligations – Accrued Long-term Benefit Liability	(79)	(74)	(369)	(511)
Funded (Underfunded) Status	$ 395	$ 238	$ (373)	$ (516)

SFAS 158 Amounts Recognized in AEP's Accumulated Other Comprehensive Income (AOCI) as of December 31, 2007 and 2006

	Pension Plans		Other Postretirement Benefit Plans	
	2007	2006	2007	2006
Components		(in millions)		
Net Actuarial Loss	$ 534	$ 759	$ 231	$ 354
Prior Service Cost (Credit)	14	(5)	4	4
Transition Obligation	-	-	97	124
Pretax AOCI	$ 548	$ 754	$ 332	$ 482
Recorded as				
Regulatory Assets	$ 453	$ 582	$ 204	$ 293
Deferred Income Taxes	33	60	45	66
Net of Tax AOCI	62	112	83	123
Pretax AOCI	$ 548	$ 754	$ 332	$ 482

Components of the Change in AEP's Plan Assets and Benefit Obligations Recognized in Pretax AOCI during the year ended December 31, 2007 are as follows:

	Pension Plans	Other Postretirement Benefit Plans
	(in millions)	
2007 Actuarial Gain	$ (166)	$ (111)
Amortization of Actuarial Loss	(59)	(12)
2007 Prior Service Cost	19	-
Amortization of Transition Obligation	-	(27)
Total 2007 Pretax AOCI Change	$ (206)	$ (150)

Pension and Other Postretirement Plans' Assets

The asset allocations for AEP's pension plans at the end of 2007 and 2006, and the target allocation for 2008, by asset category, are as follows:

	Target Allocation	Percentage of Plan Assets at Year End	
	2008	2007	2006
Asset Category			
Equity Securities	55%	57%	63%
Real Estate	5%	6%	6%
Debt Securities	39%	36%	26%
Cash and Cash Equivalents	1%	1%	5%
Total	100%	100%	100%

The asset allocations for AEP's other postretirement benefit plans at the end of 2007 and 2006, and target allocation for 2008, by asset category, are as follows:

	Target Allocation	Percentage of Plan Assets at Year End	
	2008	2007	2006
Asset Category			
Equity Securities	66%	62%	66%
Debt Securities	33%	35%	32%
Cash and Cash Equivalents	1%	3%	2%
Total	100%	100%	100%

AEP's investment strategy for the employee benefit trust funds is to use a diversified portfolio of investments to achieve an acceptable rate of return while managing the interest rate sensitivity of the plans' assets relative to the plans' liabilities. To minimize investment risk, AEP's employee benefit trust funds are broadly diversified among classes of assets, investment strategies and investment managers. AEP regularly reviews the actual asset allocation and periodically rebalances the investments to AEP's targeted allocation when considered appropriate. AEP's investment policies and guidelines allow investment managers in approved strategies to use financial derivatives to obtain or manage market exposures and to hedge assets and liabilities. The investment policies prohibit investment in AEP securities, with the exception of proportionate and immaterial holdings of AEP securities in passive index strategies.

The value of the pension plans' assets increased to $4.5 billion at December 31, 2007 from $4.3 billion at December 31, 2006. The qualified plans paid $277 million in benefits to plan participants during 2007 (nonqualified plans paid $7 million in benefits). The value of AEP's Postretirement Plans' assets increased to $1.4 billion in December 31, 2007 from $1.3 billion at December 31, 2006. The Postretirement Plans paid $130 million in benefits to plan participants during 2007.

AEP bases the 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.

	December 31,	
	2007	2006
Accumulated Benefit Obligation	(in millions)	
Qualified Pension Plans	$ 3,914	$ 3,861
Nonqualified Pension Plans	77	78
Total	$ 3,991	$ 3,939

For the underfunded pension plans that had an accumulated benefit obligation in excess of plan assets, the projected benefit obligation, accumulated benefit obligation, and fair value of plan assets of these plans at December 31, 2007 and 2006 were as follows:

	Underfunded Pension Plans	
	December 31,	
	2007	2006
	(in millions)	
Projected Benefit Obligation	$ 81	$ 82
Accumulated Benefit Obligation	$ 77	$ 78
Fair Value of Plan Assets	-	-
Accumulated Benefit Obligation Exceeds the Fair Value of Plan Assets	$ 77	$ 78

Actuarial Assumptions for Benefit Obligations

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

	Pension Plans		Other Postretirement Benefit Plans	
Assumptions	2007	2006	2007	2006
Discount Rate	6.00%	5.75%	6.20%	5.85%
Rate of Compensation Increase	5.90%(a)	5.90%(a)	N/A	N/A

(a) Rates are for base pay only. In addition, an amount is added to reflect target incentive compensation for exempt employees and overtime and incentive pay for nonexempt employees.

N/A = Not Applicable

To determine a discount rate, AEP uses a duration-based method by constructing a hypothetical portfolio of high quality corporate bonds similar to those included in the Moody's Aa bond index with a duration matching the benefit plan liability. The composite yield on the hypothetical bond portfolio is used as the discount rate for the plan.

For 2007, the rate of compensation increase assumed varies with the age of the employee, ranging from 5% per year to 11.5% per year, with an average increase of 5.9%.

Estimated Future Benefit Payments and Contributions

Information about the 2008 expected cash flows for the pension (qualified and nonqualified) and other postretirement benefit plans is as follows:

Employer Contributions	Pension Plans	Other Postretirement Benefit Plans
	(in millions)	
Required Contributions (a)	$ 8	$ 4
Additional Discretionary Contributions	-	73

(a) Contribution required to meet minimum funding requirement per the U.S. Department of Labor plus direct payments for unfunded benefits.

The contribution to the pension plans is based on the minimum amount required by the U.S. Department of Labor and the amount to pay unfunded nonqualified benefits. The contribution to the other postretirement benefit plans is generally based on the amount of the other postretirement benefit plans' periodic benefit cost for accounting purposes as provided for in agreements with state regulatory authorities, plus the additional discretionary contribution of AEP's Medicare subsidy receipts.

The table below reflects the total benefits expected to be paid from the plan or from the employer's assets, including both the employer's share of the benefit cost and the participants' share of the cost, which is funded by participant contributions to the plan. Medicare subsidy receipts are shown in the year of the corresponding benefit payments, even though actual cash receipts are expected early in the following year. 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 AEP's pension benefits and other postretirement benefits are as follows:

	Pension Plans	Other Postretirement Benefit Plans	
	Pension Payments	Benefit Payments	Medicare Subsidy Receipts
		(in millions)	
2008	$ 356	$ 111	$ (10)
2009	362	121	(11)
2010	363	131	(11)
2011	363	141	(12)
2012	368	149	(13)
Years 2013 to 2017, in Total	1,861	864	(82)

Components of Net Periodic Benefit Cost

The following table provides the components of AEP's net periodic benefit cost for the plans for fiscal years 2007, 2006 and 2005:

	Pension Plans			Other Postretirement Benefit Plans		
	Years Ended December 31,					
	2007	2006	2005	2007	2006	2005
	(in millions)					
Service Cost	$ 96	$ 97	$ 93	$ 42	$ 39	$ 42
Interest Cost	235	231	228	104	102	107
Expected Return on Plan Assets	(340)	(335)	(314)	(104)	(94)	(92)
Amortization of Transition Obligation	-	-	-	27	27	27
Amortization of Prior Service Cost (Credit)	-	(1)	(1)	-	-	-
Amortization of Net Actuarial Loss	59	79	55	12	22	25
Net Periodic Benefit Cost	50	71	61	81	96	109
Capitalized Portion	(14)	(21)	(17)	(25)	(27)	(33)
Net Periodic Benefit Cost Recognized as Expense	$ 36	$ 50	$ 44	$ 56	$ 69	$ 76

Estimated amounts expected to be amortized to net periodic benefit costs from AEP's pretax accumulated other comprehensive income during 2008 are shown in the following table:

	Pension Plans	Other Postretirement Benefit Plans
	(in millions)	
Net Actuarial Loss	$ 26	$ 5
Prior Service Cost	1	1
Transition Obligation	-	27
Total Estimated 2008 Pretax AOCI Amortization	$ 27	$ 33

The following table provides TNC's net periodic benefit cost for the plans for the years ended December 31, 2007, 2006 and 2005:

	Pension Plans			Other Postretirement Benefit Plans		
	Years Ended December 31,					
	2007	2006	2005	2007	2006	2005
	(in thousands)					
Benefit Cost	$ 281	$ 1,303	$ 158	$ 2,523	$ 2,861	$ 3,291

Actuarial Assumptions for Net Periodic Benefit Costs

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

	Pension Plans			Other Postretirement Benefit Plans		
	2007	**2006**	**2005**	**2007**	**2006**	**2005**
Discount Rate	5.75%	5.50%	5.50%	5.85%	5.65%	5.80%
Expected Return on Plan Assets	8.50%	8.50%	8.75%	8.00%	8.00%	8.37%
Rate of Compensation Increase	5.90%	5.90%	3.70%	N/A	N/A	N/A

N/A = Not Applicable

The expected return on plan assets for 2007 was determined by evaluating historical returns, the current investment climate (yield on fixed income securities and other recent investment market indicators), rate of inflation, and current prospects for economic growth.

The health care trend rate assumptions as of January 1, used for other postretirement benefit plans measurement purposes are shown below:

Health Care Trend Rates	2007	2006
Initial	7.5%	8.0%
Ultimate	5.0%	5.0%
Year Ultimate Reached	2012	2009

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	$ 19	$ (16)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	185	(154)

AEP Savings Plan

TNC participates in an AEP sponsored defined contribution retirement savings plans for substantially all employees. These plans offer participants an opportunity to contribute a portion of their pay, include features under Section 401(k) of the Internal Revenue Code and provide for company matching contributions. The matching contributions to the plan are 75% of the first 6% of eligible compensation contributed by the employee. The cost for contributions to these plans totaled $1.1 million in 2007, $1.1 million in 2006 and $1 million in 2005.

8. BUSINESS SEGMENTS

TNC has one reportable segment, a generation, transmission and distribution business. TNC's other activities are insignificant.

9. DERIVATIVES, HEDGING AND FINANCIAL INSTRUMENTS

DERIVATIVES AND HEDGING

SFAS 133 requires recognition of all qualifying derivative instruments as either assets or liabilities in the statement of financial position at fair value. The fair values of derivative instruments accounted for using MTM accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes and supply and demand market data and assumptions. The fair values determined are reduced by the appropriate valuation adjustments for items such as discounting, liquidity and credit quality. Credit risk is the risk that the counterparty to the contract will fail to perform or fail to pay amounts due. Liquidity risk represents the influence that imperfections in marketplace transparency may cause pricing to be less than or more than what the price should be based purely on supply and demand. Because energy markets are imperfect and volatile, there are inherent risks related to the underlying assumptions in models used to fair value open long-term risk management contracts. 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 the approach at estimating current market consensus for forward prices in the current period. This is particularly true for long-term contracts.

Certain qualifying derivative instruments have been designated as normal purchases or normal sales contracts, as provided in SFAS 133. Derivative contracts that have been designated as normal purchases or normal sales under SFAS 133 are not subject to MTM accounting treatment and are recognized in the Consolidated Statements of Income on an accrual basis.

TNC's accounting for the changes in the fair value of a derivative instrument depends on whether it qualifies for and has been designated as part of a hedging relationship and further, on the type of hedging relationship. For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows that is attributable to a particular risk), TNC initially reports the effective portion of the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income (Loss) until the period the hedged item affects earnings. TNC recognizes any hedge ineffectiveness in earnings immediately during the period of change.

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in Revenues on a net basis in TNC's Consolidated Statements of Income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in Revenues or Expenses on the Consolidated Statements of Income depending on the relevant facts and circumstances.

Cash Flow Hedging Strategies

Prior to TNC's FERC-approved removal from the SIA and CSW Operating Agreement, TNC entered into, and designated as cash flow hedges, certain derivative transactions for the purchase and sale of electricity and natural gas in order to manage the variable price risk related to the forecasted purchase and sale of these commodities. At various times during 2006 and 2005, TNC designated cash flow hedge relationships using these commodities. Management closely monitored the potential impacts of commodity price changes, and where appropriate, entered into derivative transactions to protect margins for a portion of future electricity sales and fuel purchases. Realized gains and losses on these derivatives designated as cash flow hedges were included in Revenues or fuel expense, depending on the specific nature of the risk being hedged. TNC did not hedge all variable price risk exposure related to energy commodities. At various times during 2006 and 2005, TNC recognized immaterial amounts in earnings related to hedge ineffectiveness.

The following table represents the activity in Accumulated Other Comprehensive Income (Loss) for derivative contracts that qualify as cash flow hedges for the years 2005, 2006 and 2007:

	(in thousands)
Balance at December 31, 2004	$ 285
Effective portion of changes in fair value	(290)
Reclasses from AOCI to Net Income	(106)
Balance at December 31, 2005	(111)
Effective portion of changes in fair value	(703)
Impact Due to Changes in SIA	98
Reclasses from AOCI to Net Income	14
Balance at December 31, 2006	(702)
Effective portion of changes in fair value	702
Reclasses from AOCI to Net Income	-
Balance at December 31, 2007	$ -

FINANCIAL INSTRUMENTS

The fair values of Long-term Debt are based on quoted market prices for the same or similar issues and the current 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 TNC's significant financial instruments at December 31, 2007 and 2006 are summarized in the following table.

	December 31, 2007		December 31, 2006	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
Long-term Debt	$ 268,875	$ 271,815	$ 276,936	$ 277,842

10. INCOME TAXES

The details of income taxes before cumulative effect of accounting change as reported are as follows:

	Years Ended December 31, 2007	2006	2005
	(in thousands)		
Income Tax Expense (Credit):			
Current	$ 21,948	$ 5,751	$ 24,426
Deferred	(737)	(227)	(4,578)
Deferred Investment Tax Credits	(1,119)	(1,270)	(1,271)
Total Income Tax	$ 20,092	$ 4,254	$ 18,577

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

	Years Ended December 31,		
	2007	2006	2005
	(in thousands)		
Net Income	$ 39,349	$ 14,943	$ 33,004
Cumulative Effect of Accounting Change	-	-	8,472
Income Taxes	20,092	4,254	18,577
Pretax Income	$ 59,441	$ 19,197	$ 60,053
Income Tax on Pretax Income at Statutory Rate (35%)	$ 20,804	$ 6,719	$ 21,019
Increase (Decrease) in Income Tax resulting from the following items:			
Depreciation	(444)	(500)	(513)
Investment Tax Credits, Net	(1,119)	(1,270)	(1,271)
State and Local Income Taxes	1,010	(759)	718
Other	(159)	64	(1,376)
Total Income Taxes	$ 20,092	$ 4,254	$ 18,577
Effective Income Tax Rate	33.8%	22.2%	30.9%

The following table shows the elements of the net deferred tax liability and the significant temporary differences:

	December 31,	
	2007	2006
	(in thousands)	
Deferred Tax Assets	$ 39,651	$ 44,915
Deferred Tax Liabilities	(162,225)	(168,963)
Net Deferred Tax Liabilities	$ (122,574)	$ (124,048)
Property Related Temporary Differences	$ (126,380)	$ (124,197)
Amounts Due from Customers for Future Federal Income Taxes	3,044	3,392
Deferred State Income Taxes	(1,184)	(1,471)
Deferred Income Taxes on Other Comprehensive Loss	5,012	5,470
Deferred Fuel and Purchased Power	812	3,525
Accrued Pensions	(11,076)	(10,131)
Provision for Refund	163	77
Regulatory Assets	(11,626)	(13,009)
All Other, Net	18,661	12,296
Net Deferred Tax Liabilities	$ (122,574)	$ (124,048)

TNC joins in the filing of a consolidated federal income tax return with its affiliates in the AEP System. The allocation of the AEP System's current consolidated federal income tax to the AEP System companies allocates the benefit of current tax losses to the AEP System companies giving rise to such losses in determining their current tax expense. The tax benefit of the Parent is allocated to its subsidiaries with taxable income. With the exception of the loss of the Parent, the method of allocation reflects a separate return result for each company in the consolidated group.

TNC and other AEP Subsidiaries are no longer subject to U.S. federal examination for years before 2000. However, TNC and other AEP Subsidiaries have filed refund claims with the IRS for years 1997 through 2000 for the CSW pre-merger tax period, which are currently being reviewed. TNC and other AEP Subsidiaries have completed the exam for the years 2001 through 2003 and have issues that will be pursued at the appeals level. The returns for the years 2004 through 2006 are presently under audit by the IRS. Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for income taxes have been made for potential liabilities resulting from such matters. In addition, TNC accrues interest on these uncertain tax positions. 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.

TNC, along with other AEP Subsidiaries, files income tax returns in various state and local jurisdictions. These taxing authorities routinely examine the tax returns and TNC and other AEP Subsidiaries are currently under examination in several state and local jurisdictions. Management believes that TNC and other AEP Subsidiaries have filed tax returns with positions that may be challenged by these tax authorities. However, management does not believe that the ultimate resolution of these audits will materially impact results of operations. With few exceptions, TNC is no longer subject to state or local income tax examinations by tax authorities for years before 2000.

Prior to the adoption of FIN 48, TNC recorded interest and penalty expense related to uncertain tax positions in tax expense accounts. With the adoption of FIN 48, TNC began recognizing interest accruals related to uncertain tax positions in interest income or expense as applicable, and penalties in Other Operation. In 2007, TNC reported $300 thousand of interest expense. TNC had approximately $800 thousand for the payment of interest and penalties accrued at December 31, 2007 and 2006.

As a result of the implementation of FIN 48 on January 1, 2007, TNC recognized a $557 thousand increase in the liabilities for unrecognized tax benefits, as well as related interest expense and penalties, which was accounted for as a reduction to the January 1, 2007 balance of retained earnings.

As of December 31, 2007, the reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

	(in millions)
Balance at January 1, 2007	$ 6.9
Increase - Tax Positions Taken During a Prior Period	-
Decrease - Tax Positions Taken During a Prior Period	(1.5)
Increase - Tax Positions Taken During the Current Year	0.2
Decrease - Settlements with Taxing Authorities	-
Decrease - Lapse of the Applicable Statute of Limitations	-
Balance at December 31, 2007	$ 5.6

The total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate is $2.6 million. Management believes there will be no significant net increase or decrease in unrecognized tax benefits within 12 months of the reporting date.

Federal Tax Legislation

In 2005, the Energy Tax Incentives Act of 2005 was signed into law. This act created a limited amount of tax credits for the building of IGCC plants. The credit is 20% of the eligible property in the construction of new plant or 20% of the total cost of repowering of an existing plant using IGCC technology. In the case of a newly constructed IGCC plant, eligible property is defined as the components necessary for the gasification of coal, including any coal handling and gas separation equipment. AEP announced plans to construct two new IGCC plants that may be eligible for the allocation of these credits. AEP filed applications for the Mountaineer and Great Bend projects with the DOE and the IRS. Both projects were certified by the DOE and qualified by the IRS. However, neither project was awarded credits during this round of credit awards. AEP will continue to pursue credits for the next round of available credits.

The Tax Increase Prevention and Reconciliation Act of 2005 (TIPRA 2005) was passed May 17, 2006. The majority of the provisions in TIPRA 2005 were directed toward individual income tax relief including the extension of reduced tax rates for dividends and capital gains through 2010. Management believes the application of this act will not materially affect TNC's results of operations, cash flows or financial condition.

The President signed the Pension Protection Act of 2006 (PPA 2006) into law on August 17, 2006. This law is directed toward strengthening qualified retirement plans and adding new restrictions on charitable contributions. Specifically, PPA 2006 concentrates on the funding of defined benefit plans and the health of the Pension Benefit Guaranty Corporation. PPA 2006 imposes new minimum funding rules for multiemployer plans as well as increasing the deduction limitation for contributions to multiemployer defined benefit plans. Due to the significant funding of the AEP pension plans in 2005, the Act will not materially affect TNC's results of operations, cash flows or financial condition.

On December 20, 2006, the Tax Relief and Health Care Act of 2006 (TRHCA 2006) was signed into law. The primary purpose of the bill was to extend expiring tax provisions for individuals and business taxpayers and provide increased tax flexibility around medical benefits. In addition to extending the lower capital gains and dividend tax rates for individuals, TRHCA 2006 extended the research credit and for 2007 provided a new alternative formula for determining the research credit. The application of TRHCA 2006 is not expected to materially affect TNC's results of operations, cash flows or financial condition.

Several tax bills and other legislation with tax-related sections were enacted in 2007, including the Tax Technical Corrections Act of 2007, the Tax Increase Prevention Act of 2007 and the Energy Independence and Security Act of 2007. The tax law changes enacted in 2007 are not expected to materially affect TNC's results of operations, cash flows or financial condition.

State Tax Legislation

On June 30, 2005, the Governor of Ohio signed Ohio House Bill 66 into law enacting sweeping tax changes impacting all companies doing business in Ohio. Most of the significant tax changes will be phased in over a five-year period, while some of the less significant changes became fully effective July 1, 2005. Changes to the Ohio franchise tax, nonutility property taxes, and the new commercial activity tax are subject to phase-in. The Ohio franchise tax will fully phase-out over a five-year period beginning with a 20% reduction in state franchise tax for taxable income accrued during 2005. In 2005, TNC reversed $120 thousand of SFAS 109 Regulatory Assets, $75 thousand of state income tax expense and $195 thousand of deferred state income tax liabilities that are not expected to reverse during the phase-out.

The new legislation also imposes a new commercial activity tax at a fully phased-in rate of 0.26% on all Ohio gross receipts. The new tax is being phased-in over a five-year period that began July 1, 2005 at 23% of the full 0.26% rate.

In the second quarter of 2006, the Texas state legislature replaced the existing franchise/income tax with a gross margin tax at a 1% rate for electric utilities. Overall, the new law reduces Texas income tax rates and is effective January 1, 2007. The new gross margin tax is income-based for purposes of the application of SFAS 109 "Accounting for Income Taxes." Based on the new law, management reviewed deferred tax liabilities with consideration given to the rate changes and changes to the allowed deductible items with temporary differences. As a result, in the second quarter of 2006 TNC recorded decreases of $4.8 million in SFAS 109 Regulatory Assets, $1.3 million in state income tax expense and $6.1 million in deferred state income tax liabilities.

11. LEASES

Leases of property, plant and equipment are for periods up to 13 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 Other Operation and Maintenance expense in accordance with rate-making treatment for regulated operations. The components of rental costs are as follows:

	Years Ended December 31,		
	2007	**2006**	**2005**
Lease Rental Costs		**(in thousands)**	
Net Lease Expense on Operating Leases	$ 3,137	$ 2,812	$ 2,275
Amortization of Capital Leases	526	397	249
Interest on Capital Leases	93	82	34
Total Lease Rental Costs	$ 3,756	$ 3,291	$ 2,558

The following table shows the property, plant and equipment under capital leases and related obligations recorded on TNC's Consolidated Balance Sheets. Capital lease obligations are included in Current Liabilities – Other and Noncurrent Liabilities – Deferred Credits and Other on TNC's Consolidated Balance Sheets.

	December 31, 2007	2006
	(in thousands)	
Property, Plant and Equipment Under Capital Leases		
Total Property, Plant and Equipment Under Capital Leases – Other	$ 2,189	$ 2,110
Accumulated Amortization	893	467
Net Property, Plant and Equipment Under Capital Leases	$ 1,296	$ 1,643
Obligations Under Capital Leases		
Noncurrent Liability	$ 748	$ 1,137
Liability Due Within One Year	548	506
Total Obligations Under Capital Leases	$ 1,296	$ 1,643

Future minimum lease payments consisted of the following at December 31, 2007:

Future Minimum Lease Payments	Capital Leases	Noncancelable Operating Leases
	(in thousands)	
2008	$ 607	$ 2,991
2009	447	2,890
2010	245	2,494
2011	94	1,666
2012	10	1,161
Later Years	-	3,076
Total Future Minimum Lease Payments	$ 1,403	$ 14,278
Less Estimated Interest Element	107	
Estimated Present Value of Future Minimum Lease Payments	$ 1,296	

12. FINANCING ACTIVITIES

Preferred Stock

Par Value	Authorized Shares	Shares Outstanding at December 31, 2007	Call Price at December 31, 2007 (a)	Series	Redemption	December 31, 2007	2006
						(in thousands)	
$ 100	810,000	23,486	$ 107.00	4.40%	Any time	$ 2,349	$ 2,349

(a) The cumulative preferred stock is callable at the price indicated plus accrued dividends.

Series	Number of Shares Redeemed for the Years Ended December 31, 2007	2006	2005
4.40%	-	80	-

Long-term Debt

There are certain limitations on establishing liens against TNC's assets under its indentures. None of the long-term debt obligations of TNC have been guaranteed or secured by AEP or any of its affiliates.

The following details long-term debt outstanding at December 31, 2007 and 2006:

Type of Debt	Maturity	Interest Rates at December 31, 2007	Interest Rates at December 31, 2006	December 31, 2007	December 31, 2006
				(in thousands)	
Pollution Control Bonds, Red River Auth. of Texas, Series 1996 (a)	2020	-	6.00%	$ -	$ 44,310
Pollution Control Bonds, Red River Auth. of Texas, Series 2007 (a)	2020	4.45%	-	44,310	-
Total Pollution Control Bonds				44,310	44,310
Senior Unsecured Notes, Series A	2013	5.50%	5.50%	225,000	225,000
Unamortized Premium (Discount)				(435)	(525)
Total Senior Unsecured Notes				224,565	224,475
First Mortgage Bonds, Series P (b)	2007	-	7.75%	-	8,151
Total First Mortgage Bonds				-	8,151
Total Long-term Debt				268,875	276,936
Less: Long-term Debt Due Within One Year				-	8,151
Long-term Debt				$ 268,875	$ 268,785

(a) Under the terms of the Pollution Control Bonds, TNC 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 rates are subject to periodic adjustment. Interest payments are made semi-annually. Letters of credit from banks, standby bond purchase agreements and insurance policies support certain series.

(b) In December 2005, cash and treasury securities were deposited with a trustee to defease the remaining TNC outstanding First Mortgage Bond. Interest payments were made semi-annually. The defeased TNC First Mortgage Bond was retired in June 2007. The defeased TNC First Mortgage Bond had a balance of $8 million at December 31, 2006. Trust fund assets related to this obligation of $9 million are included in Other Cash Deposits on TNC's Consolidated Balance Sheets at December 31, 2006. Trust fund assets are restricted for exclusive use in funding the interest and principal due on the First Mortgage Bonds.

At December 31, 2007 future annual long-term debt payments are as follows:

	2008	2009	2010	2011	2012	After 2012	Total
				(in thousands)			
Principal Amount	$ -	$ -	$ -	$ -	$ -	$ 269,310	$ 269,310
Unamortized Discount							(435)
Total Long-term Debt							$ 268,875

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 Nonutility Money Pool, which funds the majority of the nonutility subsidiaries. The AEP System corporate borrowing program operates in accordance with the terms and conditions approved in a regulatory order. The amount of outstanding loans (borrowings) to/from the Utility Money Pool and the Nonutility Money Pool as of December 31, 2007 and 2006 are included in Advances to/from Affiliates on TNC's balance sheets. TNC's Utility Money Pool activity and corresponding authorized borrowing limits for the years ended December 31, 2007 and 2006 are described in the following table:

Year	Maximum Borrowings from Utility Money Pool	Maximum Loans to Utility Money Pool	Average Borrowings from Utility Money Pool	Average Loans to Utility Money Pool	Borrowings from Utility Money Pool as of December 31,	Authorized Short-Term Borrowing Limit
	(in thousands)					
2007	$ 59,565	$ 3,200	$ 32,020	$ 2,365	$ 50,795	$ 250,000
2006	23,660	34,574	7,988	8,381	235	250,000

The activity in the above table does not include short-term lending activity of TNC's wholly-owned subsidiary, AEP Texas North Generation Company LLC (TNGC), who, in 2006, became a participant in the Nonutility Money Pool. For the years ended December 31, 2007 and 2006, TNGC had the following activity in the Nonutility Money Pool:

Year	Maximum Borrowings from Nonutility Money Pool	Maximum Loans to Nonutility Money Pool	Average Borrowings from Nonutility Money Pool	Average Loans to Nonutility Money Pool	Loans to Nonutility Money Pool as of December 31, 2007
	(in thousands)				
2007	$ -	$ 20,152	$ -	$ 16,033	$ 17,284
2006	10	13,947	8	13,808	13,778

Maximum, minimum and average interest rates for funds either borrowed from or loaned to the Utility Money Pool for the years ended December 31, 2007, 2006 and 2005 are summarized in the following table:

Years Ended December 31,	Maximum Interest Rates for Funds Borrowed from the Utility Money Pool	Minimum Interest Rates for Funds Borrowed from the Utility Money Pool	Maximum Interest Rates for Funds Loaned to the Utility Money Pool	Minimum Interest Rates for Funds Loaned to the Utility Money Pool	Average Interest Rates for Funds Borrowed from the Utility Money Pool	Average Interest Rates for Funds Loaned to the Utility Money Pool
2007	5.94%	5.16%	5.35%	5.34%	5.43%	5.35 %
2006	5.41%	3.32%	5.22%	3.83%	4.60%	4.56 %
2005	4.45%	4.40%	4.49%	1.63%	4.41%	3.29 %

Maximum, minimum and average interest rates for funds either borrowed from or loaned to the Nonutility Money Pool for the years ended December 31, 2007 and 2006 are summarized in the following table:

Years Ended December 31,	Maximum Interest Rates for Funds Borrowed from the Nonutility Money Pool	Minimum Interest Rates for Funds Borrowed from the Nonutility Money Pool	Maximum Interest Rates for Funds Loaned to the Nonutility Money Pool	Minimum Interest Rates for Funds Loaned to the Nonutility Money Pool	Average Interest Rates for Funds Borrowed from the Nonutility Money Pool	Average Interest Rates for Funds Loaned to the Nonutility Money Pool
2007	-%	-%	5.94%	5.16%	-%	5.45 %
2006	5.39%	5.34%	5.52%	5.13%	5.36%	5.36 %

Interest expense and interest income related to the Utility Money Pool are included in Interest Expense and Interest Income, respectively, in TNC's Consolidated Statements of Income. For amounts borrowed from and advanced to the Utility Money Pool, TNC incurred the following amounts of interest expense and earned the following amounts of interest income, respectively, for the years ended December 31, 2007, 2006 and 2005:

	Years Ended December 31,		
	2007	**2006**	**2005**
		(in thousands)	
Interest Expense	$ 1,747	$ 274	$ 8
Interest Income	1	112	1,897

Interest expense and interest income related to the Nonutility Money Pool are included in Interest Expense and Interest Income, respectively, in TNC's Consolidated Statements of Income. For amounts borrowed from and advanced to the Nonutility Money Pool, TNC incurred the following amounts of interest expense and earned the following amounts of interest income, respectively, for the years ended December 31, 2007 and 2006:

	Years Ended December 31,	
	2007	**2006**
	(in thousands)	
Interest Expense	$ -	$ -
Interest Income	880	233

Dividend Restrictions

Under the Federal Power Act, TNC is restricted from paying dividends out of stated capital.

13. RELATED PARTY TRANSACTIONS

For other related party transactions, also see "Lines of Credit – AEP System" section of Note 12.

CSW Operating Agreement

PSO, SWEPCo and AEPSC are parties to a Restated and Amended Operating Agreement originally dated as of January 1, 1997 (CSW Operating Agreement), which was approved by the FERC. In February 2006, AEP filed with the FERC a proposed amendment to the CSW Operating Agreement to remove TCC and TNC as parties to the agreement. Pursuant to Texas electric restructuring law, those companies exited the generation and load-servicing businesses. AEP made a similar filing to remove those two companies as parties to the System Integration Agreement. The filings were approved effective May 1, 2006 and April 1, 2006, respectively.

The CSW Operating Agreement requires the parties to maintain adequate annual planning reserve margins and requires that capacity in excess of the required margins be made available for sale to other operating companies as capacity commitments. Parties are compensated for energy delivered to recipients based upon the deliverer's incremental cost plus a portion of the recipient's savings realized by the purchaser that avoids the use of more costly alternatives. Revenues and costs arising from third party sales are generally shared based on the amount of energy parties contribute that is sold to third parties.

System Integration Agreement (SIA)

AEP's System Integration Agreement, which has been approved by the FERC, provides for the integration and coordination of AEP's East companies and West companies zones. This includes joint dispatch of generation within the AEP System, and the distribution, between the two zones, of costs and benefits associated with the transfers of power between the two zones (including sales to third parties and risk management and trading activities). It is designed to function as an umbrella agreement in addition to the Interconnection Agreement and the CSW Operating Agreement, each of which controls the distribution of costs and benefits within each zone.

In November 2005, AEP filed with the FERC a proposed amendment to the SIA to change the method of allocating profits from off-system electricity sales between the East and West zones. The proposed method causes such profits to be allocated generally on the basis of the zone in which the underlying transactions occur or originate. The filing was made in accordance with a provision of the agreement that called for a re-evaluation of the allocation method effective January 1, 2006 and was approved as filed effective April 1, 2006. As discussed earlier, TNC is no longer a party to the SIA.

Power generated by or allocated or provided under the Interconnection Agreement or CSW Operating Agreement to TNC is primarily sold to REPs at market rates.

Under both the Interconnection Agreement and CSW Operating Agreement, power generated that is not needed to serve the AEP System native load is sold in the wholesale market by AEPSC on behalf of the generating subsidiary.

Affiliated Revenues and Purchases

The following table shows the revenues derived from direct sales to affiliates and other revenues for the years ended December 31, 2007, 2006 and 2005:

	Years Ended December 31,		
Related Party Revenues	**2007**	**2006**	**2005**
Direct Sales to West Affiliates	$ -	$ 17	$ 98
Direct Sales to AEPEP Affiliate	100,653	-	-
Other	3,806	33,208	47,066
Total Revenues	$ 104,459	$ 33,225	$ 47,164

The following table shows the purchased power expense incurred from purchases from the pool and affiliates for the years ended December 31, 2007, 2006 and 2005:

	Years Ended December 31,		
Related Party Purchases	**2007**	**2006**	**2005**
Purchases from West System Pool	$ -	$ 4	$ -
Direct Purchases from East Affiliates	-	11	-
Direct Purchases from West Affiliates	739	5,933	23
Total Purchases	$ 739	$ 5,948	$ 23

The above summarized related party revenues and expenses are reported as Sales to AEP Affiliates and Purchased Electricity for Resale on TNC's Consolidated Statements of Income.

AEP System Transmission Pool

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 companies and AEP West companies zones. The System Transmission Integration Agreement functions as an umbrella agreement in addition to the Transmission Equalization Agreement (TEA) and the Transmission Coordination Agreement (TCA). The System Transmission Integration Agreement contains two service schedules that govern:

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

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

APCo, CSPCo, I&M, KPCo and OPCo are parties to the TEA, dated April 1, 1984, as amended, 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).

PSO, SWEPCo, TCC, TNC and AEPSC are parties to the TCA, originally dated January 1, 1997. The TCA has been approved by the FERC and establishes a coordinating committee, which is charged with overseeing the coordinated planning of the transmission facilities of the AEP West companies, including the performance of transmission planning studies, the interaction of such companies with independent system operators (ISO) and other regional bodies interested in transmission planning and compliance with the terms of the OATT filed with the FERC and the rules of the FERC relating to such tariff.

Under the TCA, the AEP West companies delegated to AEPSC the responsibility of monitoring the reliability of their transmission systems and administering the OATT on their behalf. Prior to September 2005, TCA also provided for the allocation among the AEP West companies of revenues collected for transmission and ancillary services provided under the OATT. Since then, these allocations have been governed by the FERC-approved OATT for the SPP (with respect to PSO and SWEPCo) and PUCT-approved protocols for ERCOT (with respect to TCC and TNC).

TNC's net credits allocated under the TCA prior to September 2005, and pursuant to the ERCOT protocols as described above during the years ended December 31, 2007, 2006 and 2005 were $1.1 million, $1 million and $4.9 million, respectively.

The net credits are recorded in Other Operation on TNC's Consolidated Statements of Income.

Oklaunion PPA between TNC and AEP Energy Partners

On January 1, 2007, TNC began a 20-year Power Purchase & Sale Agreement (PPA) with an affiliate, AEP Energy Partners (AEPEP), whereby TNC agrees to sell AEPEP 100% of TNC's capacity and associated energy from its undivided interest (54.69%) in the Oklaunion plant. AEPEP is to pay TNC for the capacity and associated energy delivered to the delivery point, the sum of fuel, operation and maintenance, depreciation, capacity and all taxes other than federal income taxes applicable. A portion of the payment is fixed and is payable regardless of the level of output. There are no penalties if TNC fails to maintain a minimum availability level or exceeds a maximum heat rate level. The PPA was approved by the FERC on July 12, 2006. TNC recognizes revenues for the fuel, operations and maintenance and all other taxes on an as-billed basis. Revenue is recognized for the capacity and depreciation billed to AEPEP, on a straight-line basis over the term of the PPA as these represent the minimum payments due.

TNC recorded revenue of $93 million from AEPEP for the year ended December 31, 2007. This amount is included in Sales to AEP Affiliates on TNC's 2007 Consolidated Statements of Income.

SPP Customers and Assets Transferred from TNC to SWEPCo

SWEPCo's and approximately 3% of TNC's businesses were in SPP. A petition was filed in May 2006 requesting approval to transfer Mutual Energy SWEPCO L.P.'s (a subsidiary of AEP C&I Company, LLC) customers and TNC's facilities and certificated service territory located in the SPP area to SWEPCo. In January 2007, the final regulatory approval was received for the transfers. The transfers were effective February 2007 and were recorded at net book value of $12 million.

Jointly-Owned Electric Utility Plant

PSO and TNC jointly own the Oklaunion power plant along with two nonaffiliated companies. TCC sold its share to one of the nonaffiliated companies in February 2007. The costs of operating the facility are apportioned between owners based on ownership interests. Each company's share of these costs is included in the appropriate expense accounts on its respective income statement. TNC's investment in this plant is included in Property, Plant and Equipment on its balance sheets.

Gas Purchases from HPL

Prior to its sale in January 2005, HPL acquired physical gas in the spot market and sold it to TNC at cost for TNC's fuel requirements. TNC's purchases from HPL were $42 thousand for the year ended December 31, 2005 and are included in Fuel and Other Consumables Used for Electric Generation on TNC's Consolidated Statement of Income.

Purchased Power from Sweeny

On behalf of the AEP West companies, CSPCo entered into a ten year Power Purchase Agreement (PPA) with Sweeny, which was 50% owned by AEP. The PPA was for unit contingent power up to a maximum of 315 MW from January 1, 2005 through December 31, 2014. The delivery point for the power under the PPA was in TCC's system. The power was sold in ERCOT. Prior to May 1, 2006, the purchase of Sweeny power and its sale to nonaffiliates were shared among the AEP West companies under the CSW Operating Agreement. After May 1, 2006, the purchases and sales were shared between PSO and SWEPCo. See "CSW Operating Agreement" section of this note. In April 2007, AEP Energy Partners (AEPEP) was assigned the Sweeny PPA from CSPCo and became responsible for purchasing the Sweeny power instead of PSO and SWEPCo. In October 2007, AEP sold its 50% interest in the Sweeny facility along with the ten year PPA to Conoco Phillips. TNC's purchases from Sweeny were $4.2 million and $27.8 million for the years ended December 31, 2006 and 2005, respectively. These amounts are recorded in Purchased Electricity for Resale on TNC's income statements.

Sales and Purchases of Property

TNC had sales of electric property to SWEPCo and TCC individually amounting to $100 thousand or more, for the year ended December 31, 2007 of $11.6 million and $2.3 million, respectively.

In addition, TNC had aggregate affiliated sales and purchases of meters and transformers for the years ended December 31, 2007, 2006 and 2005 as shown in the following table:

	I&M	PSO	SWEPCo	TCC	TOTAL
Sales			(in thousands)		
2007	$ 1	$ 10	$ 456	$ 199	$ 666
2006	-	17	4	209	230
2005	-	-	17	317	334
Purchases					
2007	$ -	$ 2	$ 13	$ 763	$ 778
2006	-	2	-	1,266	1,268
2005	-	3	3	1,642	1,648

The amounts above are recorded in Property, Plant and Equipment. Transfers are performed at cost.

AEPSC

AEPSC provides certain managerial and professional services to AEP System companies. The costs of the services are billed to TNC by AEPSC on a direct-charge basis, whenever possible, and on reasonable bases of proration for services that benefit multiple companies. 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. Billings from AEPSC are capitalized or expensed depending on the nature of the services rendered and are recoverable from customers. During 2005, AEPSC and its billings were subject to regulation by the SEC under the PUHCA of 1935. Effective February 8, 2006, the PUHCA of 2005 was enacted, which repealed the PUHCA of 1935 and transferred the regulatory responsibility from the SEC to the FERC.

Intercompany Billings

TNC performs certain utility services for other AEP subsidiaries when necessary or practical. The costs of these services are billed on a direct-charge basis, whenever possible, or on reasonable bases of proration for services that benefit multiple companies. The billings for services are made at cost and include no compensation for the use of equity capital. Billings are capitalized or expensed depending on the nature of the services rendered.

14. PROPERTY, PLANT AND EQUIPMENT

Depreciation

TNC provides for depreciation of Property, Plant and Equipment on a straight-line basis over the estimated useful lives of property, generally using composite rates by functional class. The following table provides the annual composite depreciation rates by functional class:

2007	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Production	$ -	$ -	N.M.	N.M.	$ 292,109	$ 129,690	2.6%	20-49
Transmission	344,100	93,092	3.0%	45-75	239	86	N.M.	N.M.
Distribution	523,248	143,980	3.4%	28-70	-	-	N.M.	N.M.
CWIP	65,399	1,459	N.M.	N.M.	1,362	168	N.M.	N.M.
Other	88,763	61,886	6.6%	N.M.	71,731	68,229	N.M.	N.M.
Total	$ 1,021,510	$ 300,417			$ 365,441	$ 198,173		

2006	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Production	$ -	$ -	N.M.	N.M.	$ 290,485	$ 112,591	9.2%	20-49
Transmission	327,845	100,822	2.9%	40-75	-	-	N.M.	N.M.
Distribution	512,265	151,805	3.2%	19-55	-	-	N.M.	N.M.
CWIP	36,579	(1,457)	N.M.	N.M.	2,268	-	N.M.	N.M.
Other	99,411	64,713	9.3%	N.M.	60,040	58,487	N.M.	N.M.
Total	$ 976,100	$ 315,883			$ 352,793	$ 171,078		

2005	Regulated		Nonregulated	
Functional Class of Property	Annual Composite Depreciation Rate	Depreciable Life Ranges	Annual Composite Depreciation Rate	Depreciable Life Ranges
		(in years)		(in years)
Production	N.M.	N.M.	2.6%	20-49
Transmission	3.0%	40-75	N.M.	N.M.
Distribution	3.2%	19-55	N.M.	N.M.
Other	9.7%	N.M.	4.9%	N.M.

N.M. = Not Meaningful

For cost-based rate-regulated operations, the composite depreciation rate generally includes a component for nonasset retirement obligation (non-ARO) removal costs, which is credited to Accumulated Depreciation and Amortization. Actual removal costs incurred are charged to Accumulated Depreciation and Amortization. Any excess of accrued non-ARO removal costs over actual removal costs incurred is reclassified from Accumulated Depreciation and Amortization and reflected as a regulatory liability. For nonregulated operations, non-ARO removal cost is expensed as incurred (see "Asset Retirement Obligations" section of this note).

Asset Retirement Obligations (ARO)

TNC implemented SFAS 143 effective January 1, 2003. SFAS 143 requires entities to record a liability at fair value for any legal obligations for future asset retirements when the related assets are acquired or constructed. Upon establishment of a legal liability, SFAS 143 requires a corresponding ARO asset to be established, which will be depreciated over its useful life. Upon settlement of an ARO, TNC recognizes any difference between the ARO liability and actual costs as income or expense.

TNC adopted FIN 47 during the fourth quarter of 2005. FIN 47 interprets the application of SFAS 143. It clarifies that conditional ARO refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Entities are required to record a liability for the fair value of a conditional ARO if the fair value of the liability can be reasonably estimated. FIN 47 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an ARO.

TNC completed a review of its FIN 47 conditional ARO and concluded that legal liabilities exist for asbestos removal and disposal in general buildings and generating plants. In 2005, TNC recorded a liability for conditional ARO in accordance with FIN 47. The cumulative effect of certain retirement costs for asbestos removal related to regulated operations was charged to a regulatory liability.

The following table shows TNC's liability for conditional ARO and cumulative effect as recorded in 2005 for FIN 47:

Liability Recorded	Cumulative Effect Pretax	Cumulative Effect Net of Tax
	(in thousands)	
$ 13,514	$ (13,034)	$ (8,472)

TNC has identified, but not recognized, ARO liabilities related to electric transmission and distribution assets, as a result of certain easements on property on which assets are owned. Generally, such easements are perpetual and require only the retirement and removal of assets upon the cessation of the property's use. The retirement obligation is not estimable for such easements since TNC plans to use its facilities indefinitely. The retirement obligation would only be recognized if and when TNC abandons or ceases the use of specific easements, which is not expected.

The following is a reconciliation of the 2007 and 2006 aggregate carrying amounts of ARO for TNC:

Year	ARO at January 1,	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates	ARO at December 31,
			(in thousands)			
2007	$ 14,868	$ 937	$ 13	$ (821)	$ (4,338)	$ 10,659
2006	13,514	862	-	(33)	525	14,868

TNC's aggregate carrying amounts include ARO related to asbestos removal.

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

The amounts of AFUDC included in Allowance For Equity Funds Used During Construction on TNC's Consolidated Statements of Income was $0.3 million, $0.9 million and $0.7 million for December 31, 2007, 2006 and 2005, respectively.

The amounts of allowance for borrowed funds used during construction or interest capitalized included in Interest Expense on TNC's Consolidated Statements of Income was $1.4 million, $0.6 million and $0.4 million for December 31, 2007, 2006 and 2005, respectively.

Jointly-owned Electric Utility Plant

TNC has a 54.7% ownership share of Unit No. 1 at the Oklaunion Generating Station. In addition to TNC, the Oklaunion Generating Station is jointly-owned by PSO and various nonaffiliated companies. Each of the participating companies is obligated to pay its share of the costs in the same proportion as its ownership interest. TNC's proportionate share of the operating costs associated with this facility is included in its Consolidated Statements of Income and the investment and accumulated depreciation are reflected in its Consolidated Balance Sheets under Property, Plant and Equipment at December 31, 2007 and 2006 as follows:

	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in thousands)	
TNC's Share at December 31, 2007					
Oklaunion Generating Station (Unit No. 1) (a)	Coal	54.7%	$ 292,109	$ 1,314	$ 129,641
TNC's Share at December 31, 2006					
Oklaunion Generating Station (Unit No. 1) (a)	Coal	54.7%	$ 290,485	$ 2,164	$ 124,459

(a) Operated by PSO.

15. UNAUDITED QUARTERLY FINANCIAL INFORMATION

In management's opinion, the unaudited quarterly information reflects all normal and recurring accruals and adjustments necessary for a fair presentation of the results of operations for interim periods. Quarterly results are not necessarily indicative of a full year's operations because of various factors. TNC's unaudited quarterly financial information is as follows:

	2007 Quarterly Periods Ended			
	March 31	June 30	September 30	December 31
		(in thousands)		
Operating Revenues	$ 62,963	$ 73,880	$ 79,447	$ 63,935
Operating Income	11,668	19,371	36,288	6,675
Net Income	5,277	10,124	21,549	2,399

	2006 Quarterly Periods Ended			
	March 31	June 30	September 30	December 31
		(in thousands)		
Operating Revenues	$ 74,666	$ 82,998	$ 87,762	$ 84,044
Operating Income	8,635	184	16,368	10,100
Net Income (Loss)	3,834	(592)	8,446	3,255

There were no significant events in the fourth quarter of 2007 or 2006.