arrange a third-party sale (return-and-sale option). The lease is accounted for as an operating lease. This operating lease agreement allows us to avoid a large initial capital expenditure and to spread our railcar costs evenly over the expected twenty-year usage.

Under the lease agreement, the lessor is guaranteed that the sale proceeds under the return-and-sale option discussed above will equal at least a lessee obligation amount specified in the lease, which declines over the term from approximately 86% to 77% of the projected fair market value of the equipment. At September 30, 2005, the maximum potential loss was approximately $31 million ($20 million, net of tax) assuming the fair market value of the equipment is zero at the end of the current lease term. AEP has other railcar lease arrangements that do not utilize this type of structure.

7. ACQUISITIONS, DISPOSITIONS, DISCONTINUED OPERATIONS, ASSET IMPAIRMENTS AND ASSETS HELD FOR SALE

ACQUISITIONS

Ceredo Generating Station (Utility Operations segment)

In August 2005, APCo signed a purchase and sale agreement with Reliant Energy for the purchase of a 505 MW plant located near Ceredo, West Virginia for $100 million. This transaction is expected to be completed no later than the first quarter of 2006.

Waterford Plant (Utility Operations segment)

In May 2005, CSPCo signed a purchase and sale agreement with Public Service Enterprise Group Waterford Energy LLC for the purchase of an 821 MW plant in Waterford, Ohio. This transaction was completed in September 2005 for $218 million and the assumption of liabilities of approximately $2 million.

Monongahela Power Company (Utility Operations segment)

In June 2005, the PUCO ordered CSPCo to explore the purchase of the Ohio service territory of Monongahela Power, which includes approximately 29,000 customers. On August 2, 2005, we agreed to terms of a transaction, which includes the transfer of Monongahela Power's Ohio customer base and the assets that serve those customers to CSPCo for an estimated sales price of approximately $45 million. The sale price will be adjusted based on book values of the acquired assets and liabilities at the closing date. In addition, CSPCo will pay $10 million to compensate Monongahela Power for its termination of certain generation cost recovery litigation in Ohio. Hearings at the PUCO were held in September 2005 and we anticipate the purchase, subject to regulatory approval, to close late in the fourth quarter of 2005. Also included in the proposed transaction is a power purchase agreement under which Allegheny Power, Monongahela Power's parent company, will provide the power requirements of the acquired customers through May 31, 2007.

DISPOSITIONS

Houston Pipe Line Company (HPL) (Investments - Gas Operations segment)

In January 2005, we sold a 98% controlling interest in HPL, 30 billion cubic feet (BCF) of working gas and working capital for approximately $1 billion, subject to a working capital and inventory true-up adjustment. We retained a 2% ownership interest in HPL and provide certain transitional administrative services to the buyer. Although the assets have been legally transferred, it is not possible to determine all costs associated with the transfer until the Bank of America (BOA) litigation is resolved. Accordingly, we have deferred the excess of the sales price over the carrying cost of the net assets transferred as a deferred gain of $373 million as of September 30, 2005, which is reflected in Deferred Credits and Other on our accompanying Condensed Consolidated Balance Sheets and is subject to further purchase price true-up adjustments as defined in the contract. We provided an indemnity in an amount up to the purchase price to the purchaser for damages, if any, arising from litigation with BOA and a resulting inability to use the cushion gas (see "Enron Bankruptcy - Right to use of cushion gas agreements" section of Note 5). The HPL operations do not meet the criteria to be shown as discontinued operations due to continuing involvement associated with various contractual obligations. Significant continuing involvement includes cash flows from long-term gas contracts with the buyer through 2008, the cushion gas arrangement and our 2% ownership interest.

We also have a put option expiring in 2006, which allows us to sell our remaining 2% interest to the buyer for approximately $16 million.

Pacific Hydro Limited (Investments - Other segment)

In March 2005, we signed an agreement with Acciona, S.A. for the sale of our equity investment in Pacific Hydro Limited for approximately $88 million. The sale was contingent on Acciona obtaining a controlling interest in Pacific Hydro Limited. The sale was consummated in July 2005 and we recognized a pretax gain of $56 million.

Texas REPs (Utility Operations segment)

In December 2002, we sold two of our Texas REPs to Centrica, a UK-based provider of retail energy. The sales price was $146 million plus certain other payments including an earnings-sharing mechanism (ESM) for AEP and Centrica to share in the earnings of the sold business for the years 2003 through 2006. The method of calculating the annual earnings-sharing amount was included in the Purchase and Sales Agreement.

In March 2005, AEP and Centrica entered into a series of agreements resulting in the resolution of open issues related to the sale and the disputed ESM payments for 2003 and 2004. Also in March 2005, we received payments related to the ESM payments of $45 million and $70 million for 2003 and 2004, respectively, resulting in a pretax gain of $112 million in the first quarter of 2005, which is reflected in Other Income on our accompanying Condensed Consolidated Statements of Income. The ESM payments are contingent on Centrica's future operating results and are capped at $70 million and $20 million for 2005 and 2006, respectively. Any shortfall below the potential $70 million for 2005 will be added to the 2006 cap.

Texas Plants - Oklaunion Power Station (Utility Operations segment)

In January 2004, we signed an agreement to sell TCC's 7.81% share of Oklaunion Power Station for approximately $43 million (subject to closing adjustments) to an unrelated party. By May 2004, we received notice from the two nonaffiliated co-owners of the Oklaunion Power Station, announcing their decision to exercise their right of first refusal with terms similar to the original agreement. In June 2004 and September 2004, we entered into sales agreements with both of our nonaffiliated co-owners for the sale of TCC's 7.81% ownership of the Oklaunion Power Station. These agreements are currently being challenged in Dallas County, Texas State District Court by the unrelated party with which we entered into the original sales agreement. The unrelated party alleges that one co-owner has exceeded its legal authority and that the second co-owner did not exercise its right of first refusal in a timely manner. The unrelated party has requested that the court declare the co-owners' exercise of their rights of first refusal void. The court entered a judgment in favor of the unrelated party on October 10, 2005. TCC and the other nonaffiliated co-owners filed an appeal to the Fifth State Court of Appeals in Dallas. Oral argument has been requested but no date has been set. Briefing is scheduled to be completed by November 17, 2005. We cannot predict when these issues will be resolved. We do not expect the sale to have a significant effect on our future results of operations. TCC's assets and liabilities related to the Oklaunion Power Station have been classified as Assets Held for Sale and Liabilities Held for Sale, respectively, in our Condensed Consolidated Balance Sheets at September 30, 2005 and December 31, 2004. The plant does not meet the "component-of-an-entity" criteria because it does not have cash flows that can be clearly distinguished operationally. The plant also does not meet the "component-of-an-entity" criteria for financial reporting purposes because it does not operate individually, but rather as a part of the AEP System which includes all of the generation facilities owned by our Registrant Subsidiaries.

Texas Plants - South Texas Project (Utility Operations segment)

In February 2004, we signed an agreement to sell TCC's 25.2% share of the STP nuclear plant to an unrelated party for approximately $333 million, subject to closing adjustments. In June 2004, we received notice from co-owners of their decisions to exercise their rights of first refusal with terms similar to the original agreement. In September 2004, we entered into sales agreements with two of our nonaffiliated co-owners for the sale of TCC's 25.2% share of the STP nuclear plant. The sale was completed for approximately $314 million and the assumption of liabilities of $22 million in May 2005 and did not have a significant effect on our results of operations. The plant did not meet the "component-of-an-entity" criteria because it does not have cash flows that can be clearly distinguished operationally. The plant also did not meet the "component-of-an-entity" criteria for financial reporting purposes because it does not operate individually, but rather as a part of the AEP System which includes all of the generation facilities owned by our Registrant Subsidiaries.

DISCONTINUED OPERATIONS

Certain of our operations were determined to be discontinued operations and have been classified as such for all periods presented. Results of operations of these businesses have been reclassified for the three and nine-month periods ended September 30, 2005 and 2004 as shown in the following tables:

Three months ended September 30, 2005 and 2004:

UK

	SEEBOARD (a)	Operations (b)	Total
		(in millions)	
2005 Revenue	$ -	$ -	$ -
2005 Pretax Income	13	-	13
2005 Income After tax	20	2	22

	Pushan Power Plant	LIG (c)	UK Operations	Total
		(in millions)		
2004 Revenue	$ -	$ 1	$ 37	$ 38
2004 Pretax Income (Loss)	-	(13)	255	242
2004 Income (Loss) After tax	1	(3)	120(d)	118

Nine months ended September 30, 2005 and 2004:

	SEEBOARD (a)	UK Operations (b)	Total
		(in millions)	
2005 Revenue	$ -	$ -	$ -
2005 Pretax Income (Loss)	13	(8)	5
2005 Income (Loss) After tax	29	(3)	26

	Pushan Power Plant	LIG (c)	UK Operations	Total
		(in millions)		
2004 Revenue	$ 10	$ 165	$ 112	$ 287
2004 Pretax Income (Loss)	9	(12)	156	153
2004 Income (Loss) After tax	6	(2)	56(e)	60

(a) Relates to purchase price true-up adjustments and tax adjustments from the sale of SEEBOARD.
(b) Relates to purchase price true-up adjustments and tax adjustments from the sale of UK Operations.
(c) Includes LIG Pipeline Company and subsidiaries and Jefferson Island Storage & Hub LLC.
(d) Earnings per share related to the UK Operations was $0.30.
(e) Earnings per share related to the UK Operations was $0.14.

For the nine months ended September 30, 2004, the net decrease in cash and cash equivalents of discontinued operations was $4 million, primarily from the cash flows from operating activities of the discontinued operations.

ASSET IMPAIRMENTS

Conesville Units 1 and 2 (Utility Operations segment)

In the third quarter of 2005, following an extensive review of the commercial viability of CSPCo's Conesville Units 1 and 2, management committed to a plan to retire these units before the end of their previously estimated useful lives. As a result, Conesville Units 1 and 2 were considered retired as of the third quarter of 2005.

A pretax charge of approximately $39 million was recognized in the third quarter of 2005 related to our decision to retire the units. The impairment amount is classified as Asset Impairments and Other Related Charges in our Condensed Consolidated Statements of Income.

Compresion Bajio S de R.L. de C.V. (Investments - Other Segment)

In January 2002, we acquired a 50% interest in Compresion Bajio S de R.L. de C.V. (Bajio), a 600 MW power plant in Mexico. A pretax other-than-temporary impairment charge of $13 million was recognized in December 2004 based on an indicative bid, which did not result in a sale.

In September 2005, a pretax other-than-temporary impairment charge of approximately $7 million was recognized based on an indicative offer received in September 2005 which is under review. The impairment amount is classified as Investment Value Losses in our Condensed Consolidated Statements of Income.

ASSETS HELD FOR SALE

The assets and liabilities of the entities that were classified as held for sale at September 30, 2005 and December 31, 2004 are as follows:

	Texas Plants	
	September 30, 2005	December 31, 2004
Assets:	(in millions)	
Other Current Assets	$ 1	$ 24
Property, Plant and Equipment, Net	46	413
Regulatory Assets	-	48
Nuclear Decommissioning Trust Fund	-	143
Total Assets Held for Sale	$ 47	$ 628
Liabilities:		
Regulatory Liabilities	$ 2	$ 1
Asset Retirement Obligations	-	249
Total Liabilities Held for Sale	$ 2	$ 250

8. BENEFIT PLANS

Components of Net Periodic Benefit Costs

The following table provides the components of our net periodic benefit cost for the following plans for the three and nine months ended September 30, 2005 and 2004:

Three Months Ended September 30, 2005 and 2004:	**Pension Plans**		**Other Postretirement Benefit Plans**	
	2005	**2004**	**2005**	**2004**
	(in millions)			
Service Cost	$ 23	$ 21	$ 10	$ 10
Interest Cost	57	57	26	29
Expected (Return) on Plan Assets	(77)	(72)	(23)	(20)
Amortization of Transition (Asset) Obligation	(1)	-	6	7
Amortization of Prior Service Costs	-	(1)	-	-
Amortization of Net Actuarial Loss	13	5	5	8
Net Periodic Benefit Cost	$ 15	$ 10	$ 24	$ 34

Nine Months Ended September 30, 2005 and 2004:	**Pension Plans**		**Other Postretirement Benefit Plans**	
	2005	**2004**	**2005**	**2004**
	(in millions)			
Service Cost	$ 69	$ 64	$ 31	$ 30
Interest Cost	169	169	79	87
Expected (Return) on Plan Assets	(232)	(216)	(68)	(60)
Amortization of Transition (Asset) Obligation	(1)	1	20	21
Amortization of Prior Service Costs	-	(1)	-	-
Amortization of Net Actuarial Loss	40	13	19	26
Net Periodic Benefit Cost	$ 45	$ 30	$ 81	$ 104

9. BUSINESS SEGMENTS

As outlined in our 2004 Annual Report, our business strategy and the core of our business are to focus on domestic electric utility operations. Our previous decision that we no longer sought business interests outside of the footprint of our domestic core utility assets led us to embark on a divestiture of such noncore assets. Major asset divestitures included the sale in 2004 of two generating plants in the UK, LIG and Jefferson Island Storage & Hub, and the sale in January 2005 of a 98% interest in the HPL assets. Consequently, the significance of our three Investments segments is declining.

Our segments and their related business activities are as follows:

Utility Operations

- Domestic generation of electricity for sale to retail and wholesale customers.
- Domestic electricity transmission and distribution.

Investments - Gas Operations

- Gas pipeline and storage services.
- Gas marketing and risk management activities.

Operations of LIG, including Jefferson Island Storage, were classified as Discontinued Operations during 2003 and were sold during 2004. We sold our 98% interest in HPL during the first quarter of 2005.

Investments - UK Operations

- International generation of electricity for sale to wholesale customers.
- Coal procurement and transportation to our plants.

UK Operations were classified as Discontinued Operations during 2003 and were sold during 2004.

Investments - Other

- Bulk commodity barging operations, wind farms, IPPs and other energy supply-related businesses.

Four IPPs were sold during 2004.

With the sale of a 98% controlling interest in HPL during January 2005, we have substantially completed planned disposals of all significant noncore assets. Accordingly, effective with the quarter ended March 31, 2005, certain subsidiaries representing shared service functions and costs were reclassified to Utility Operations and Investments - Other from either Investments - Other or All Other. Such reclassifications were deemed necessary given the remaining compositions of the individual segments and the nature of the shared service functions and costs.

The tables below present segment income statement information for the three and nine months ended September 30, 2005 and 2004 and balance sheet information as of September 30, 2005 and December 31, 2004. These amounts include certain estimates and allocations where necessary. Prior year amounts have been reclassified to conform to the current year's presentation.

		Investments					
Three Months Ended September 30, 2005	**Utility Operations**	**Gas Operations**	**UK Operations**	**Other**	**All Other (a)**	**Reconciling Adjustments**	**Consolidated**
			(in millions)				
Revenues from:							
External Customers	$ 3,132	$ 73	$ -	$ 95	$ -	$ -	$ 3,300
Other Operating Segments	82	(77)	-	2	1	(8)	-

Total Revenues	$ 3,214	$ (4)	$ -	$ 97	$ 1	$ (8)	$ 3,300
Income (Loss) Before Discontinued Operations	$ 352	$ (10)	$ -	$ 28	$ (5)	$ -	$ 365
Discontinued Operations, Net of Tax	-	-	2	20	-	-	22
Net Income (Loss)	$ 352	$ (10)	$ 2	$ 48	$ (5)	$ -	$ 387
Three Months Ended September 30, 2004							
Revenues from:							
External Customers	$ 2,920	$ 760	$ -	$ 101	$ -	$ -	$ 3,781
Other Operating Segments	30	(16)	-	5	1	(20)	-
Total Revenues	$ 2,950	$ 744	$ -	$ 106	$ 1	$ (20)	$ 3,781
Income (Loss) Before Discontinued Operations	$ 359	$ (27)	$ -	$ 89	$ (9)	$ -	$ 412
Discontinued Operations, Net of Tax	-	(3)	120	1	-	-	118
Net Income (Loss)	$ 359	$ (30)	$ 120	$ 90	$ (9)	$ -	$ 530

		Investments					
Nine Months Ended September 30, 2005	**Utility Operations**	**Gas Operations**	**UK Operations**	**Other**	**All Other (a)**	**Reconciling Adjustments**	**Consolidated**
				(in millions)			
Revenues from:							
External Customers	$ 8,318	$ 449	$ -	$ 289	$ -	$ -	$ 9,056
Other Operating Segments	178	(167)	-	8	2	(21)	-
Total Revenues	$ 8,496	$ 282	$ -	$ 297	$ 2	$ (21)	$ 9,056
Income (Loss) Before Discontinued Operations	$ 952	$ (2)	$ -	$ 32	$ (45)	$ -	$ 937
Discontinued							

Operations, Net of Tax	-	-	(3)	29	-	-	26
Net Income (Loss)	$ 952	$ (2)	$ (3)	$ 61	$ (45)	$ -	$ 963
Nine Months Ended September 30, 2004							
Revenues from:							
External Customers	$ 8,009	$ 2,191	$ -	$ 356	$ -	$ -	$ 10,556
Other Operating Segments	88	23	-	32	5	(148)	-
Total Revenues	$ 8,097	$ 2,214	$ -	$ 388	$ 5	$ (148)	$ 10,556
Income (Loss) Before Discontinued Operations	$ 847	$ (41)	$ -	$ 89	$ (43)	$ -	$ 852
Discontinued Operations, Net of Tax	-	(2)	56	6	-	-	60
Net Income (Loss)	$ 847	$ (43)	$ 56	$ 95	$ (43)	$ -	$ 912

		Investments					
	Utility Operations	Gas Operations	UK Operations	Other	All Other	Reconciling Adjustments (b)	Consolidated
As of September 30, 2005	(in millions)						
Total Property, Plant and Equipment	$ 37,361	$ 2	$ -	$ 833	$ 3	$ -	$ 38,199
Accumulated Depreciation and Amortization	14,575	1	-	107	1	-	14,684
Total Property, Plant and Equipment - Net	$ 22,786	$ 1	$ -	$ 726	$ 2	$ -	$ 23,515
Total Assets	$ 33,441	$ 1,554	$ 609(c)	$ 488	$9,311	$ (9,447)	$ 35,956
Assets Held for Sale	47	-	-	-	-	-	47
As of December 31, 2004							
Total Property, Plant and Equipment	$ 36,006	$ 445	$ -	$ 832	$ 3	$ -	$ 37,286

Accumulated Depreciation and Amortization	14,355	43	-	86	1	-	14,485
Total Property, Plant and Equipment - Net	$ 21,651	$ 402	$ -	$ 746	$ 2	$ -	$ 22,801
Total Assets	$ 32,175	$ 1,789	$ 221(d)	$ 2,071	$ 8,093	$ (9,686)	$ 34,663
Assets Held for Sale	628	-	-	-	-	-	628

(a) All Other includes interest, litigation and other miscellaneous parent company expenses.
(b) Reconciling Adjustments for Total Assets primarily include the elimination of intercompany advances to affiliates and intercompany accounts receivable along with the elimination of AEP's investments in subsidiary companies.
(c) Total Assets of $609 million for the Investments-UK Operations segment include $590 million in affiliated accounts receivable related to federal income taxes that are eliminated in consolidation. The majority of the remaining $19 million in assets represents cash equivalents along with value-added tax receivables.
(d) Total Assets of $221 million for the Investments-UK Operations segment include $124 million in affiliated accounts receivable that are eliminated in consolidation. The majority of the remaining $97 million in assets represents cash equivalents and third party receivables.

10. INCOME TAXES

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, we reversed deferred state income tax liabilities of $81 million that are not expected to reverse during the phase-out. We recorded $4 million as a reduction to Income Taxes and, for the Ohio companies, established a regulatory liability for $57 million pending rate-making treatment in Ohio. For those companies in which state income taxes flow through for rate-making purposes, the adjustments reduced the regulatory assets associated with the deferred state income tax liabilities by $20 million.

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 will be phased-in over a five-year period beginning July 1, 2005 at 23% of the full 0.26% rate. The increase in Taxes Other than Income Taxes for 2005 is expected to be $2 million.

Other tax reforms effective July 1, 2005 include a reduction of the sales and use tax from 6.0% to 5.5%, the phase-out of tangible personal property taxes for our nonutility businesses, the elimination of the 10% rollback in real estate taxes and the increase in the premiums tax on insurance policies; all of which will not have a material impact on future results of operations and cash flows.

11. FINANCING ACTIVITIES

Long-term debt and other securities issued, retired and principal payments made during the first nine months of 2005 are shown in the tables below.

Company	Type of Debt	Principal Amount (in millions)		Interest Rate	Due Date
Issuances:					
AEP	Senior Unsecured Notes	$	345	4.709%	2007
APCo	Senior Unsecured Notes		200	4.95%	2015
APCo	Senior Unsecured Notes		150	4.40%	2010
APCo	Senior Unsecured Notes		250	5.00%	2017
APCo	Senior Unsecured Notes		250	5.80%	2035
OPCo	Installment Purchase Contracts		54	Variable	2029
OPCo	Installment Purchase Contracts		164	Variable	2028
OPCo	Installment Purchase Contracts		50	Variable	2014
OPCo	Installment Purchase Contracts		50	Variable	2016
OPCo	Installment Purchase Contracts		35	Variable	2022
PSO	Senior Unsecured Notes		75	4.70%	2011
SWEPCo	Senior Unsecured Notes		150	4.90%	2015
SWEPCo	Notes Payable		6	Variable	2006
TCC	Installment Purchase Contracts		162	Variable	2030
TCC	Installment Purchase Contracts		120	Variable	2028
Non-Registrant:					
AEP Subsidiary	Notes Payable		6	Variable	2009
Total Issuances		$	2,067(a)		

The above borrowing arrangements do not contain guarantees, collateral or dividend restrictions.

(a) Amount indicated on statement of cash flows of $2,045 million is net of issuance costs and unamortized premium or discount.

Company	Type of Debt	Principal Amount (in millions)		Interest Rate	Due Date
Retirements and Principal Payments:					
AEP	Senior Unsecured Notes	$	550	6.125%	2006
AEP	Senior Unsecured Notes		345	5.75%	2007
AEP	Other Debt		9	Variable	2007
AEP and Subsidiaries	Other		18(b)	Variable	Various
APCo	First Mortgage Bonds		50	8.00%	2005
APCo	First Mortgage Bonds		30	6.89%	2005
APCo	First Mortgage Bonds		45	8.00%	2025
APCo	Senior Unsecured Notes		450	4.80%	2005

OPCo	Installment Purchase Contracts	102	6.375%	2029
OPCo	Installment Purchase Contracts	80	Variable	2028
OPCo	Installment Purchase Contracts	36	Variable	2029
OPCo	Installment Purchase Contracts	50	5.45%	2014
OPCo	Installment Purchase Contracts	50	5.45%	2016
OPCo	Installment Purchase Contracts	35	5.90%	2022
OPCo	Notes Payable	4	6.81%	2008
OPCo	Notes Payable	6	6.27%	2009
PSO	First Mortgage Bonds	50	6.50%	2005
SWEPCo	Senior Unsecured Notes	200	4.50%	2005
SWEPCo	Notes Payable	5	4.47%	2011
SWEPCo	Notes Payable	3	Variable	2008
TCC	Senior Unsecured Notes	150	3.00%	2005
TCC	Senior Unsecured Notes	100	Variable	2005
TCC	First Mortgage Bonds	66	6.625%	2005
TCC	Installment Purchase Contracts	120	6.00%	2028
TCC	Securitization Bonds	29	3.54%	2005
TCC	Securitization Bonds	21	5.01%	2008
Non-Registrant:				
AEP Subsidiaries	Notes Payable	12	Variable	Various
Total Retirements		$ 2,616(c)		

(b) Amount reflects mark-to-market of risk management contracts related to long-term debt.
(c) The cash used for retirement of long-term debt indicated on statement of cash flows of $2,599 million does not include $17 million related to the mark-to-market of risk management contracts.

Preferred Stock Redemption

In January 2005, the following outstanding shares of preferred stock were redeemed:

Company	Series	Number of Shares Redeemed	Amount (in millions)
I&M	5.900%	132,000	$ 13
I&M	6.250%	192,500	19
I&M	6.875%	157,500	16
I&M	6.300%	132,450	13
OPCo	5.900%	50,000	5
			$ 66

Common Stock Repurchase

In March 2005, we repurchased 12.5 million shares of our outstanding common stock through an accelerated share repurchase agreement at an initial price of $34.63 per share plus transaction fees. The purchase of shares in the open market was completed by a broker-dealer in May and we received a purchase price adjustment of $6.45 million based on the actual cost of the shares repurchased. Based on this adjustment, our actual stock purchase price averaged $34.18 per share.

Remarketing of Senior Notes

In June 2005, we remarketed and settled $345 million of our 5.75% senior notes at a new interest rate of 4.709%. The senior notes will mature on August 16, 2007. The senior notes were originally issued in June 2002 in connection with our 9.25% equity units. We did not receive any proceeds from the mandatory remarketing. On August 16, 2005, the forward purchase contracts, which formed part of the equity units, settled and holders were required to purchase approximately 8.4 million AEP common shares.

Issuance of Common Stock

On August 16, 2005, we issued approximately 8.4 million shares of common stock in connection with the settlement of forward purchase contracts that formed a part of our outstanding 9.25% equity units. In exchange for $50 per equity unit, holders of the equity units received 1.2225 shares of AEP common stock for each purchase contract and cash in lieu of fractional shares. Each holder was not required to make any additional cash payment. The equity unit holder's purchase obligation was satisfied from the proceeds of a portfolio of U.S. Treasury securities held in a collateral account that matured on August 15, 2005. The portfolio of U.S. Treasury securities was acquired in connection with the June 2005 remarketing of the senior notes discussed above.

Subsequent Debt Issuance

In October 2005, CSPCo issued $250 million of 5.85% Senior Notes, Series F, due in October 2035.

12. COMPANY-WIDE STAFFING AND BUDGET REVIEW

As result of a company-wide staffing and budget review approximately 500 positions were identified for elimination. Pretax severance benefits expense of $24 million and $4 million was recorded (primarily in Maintenance and Other Operation) in the second and third quarters of 2005, respectively. The following table shows the total 2005 expense recorded and the remaining accrual (reflected primarily in Current Liabilities - Other) as of September 30, 2005:

	Amount (in millions)
Total Expense	28
Less: Total Payments	12
Remaining Accrual at September 30, 2005	$ 16

AEP GENERATING COMPANY

AEP GENERATING COMPANY
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

Results of Operations

Operating revenues are derived from the sale of our share of Rockport Plant energy and capacity to I&M and KPCo pursuant to FERC approved long-term unit power agreements. The unit power agreements provide for a FERC approved rate of return on common equity, a return on other capital (net of temporary cash investments) and recovery of costs including operation and maintenance, fuel and taxes. Fluctuations in Net Income are a result of terms in the unit power agreements which allow for the monthly calculation of return on total capital, largely dependent on the percentage of plant assets in service.

Third Quarter of 2005 Compared to Third Quarter of 2004

Reconciliation of Third Quarter of 2004 to Third Quarter of 2005 Net Income
(in millions)

Third Quarter of 2004 Net Income		$ 2.4
Change in Gross Margin:		
Wholesale Sales		(0.2)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(0.9)	
Taxes Other Than Income Taxes	1.0	
Total Change in Operating Expenses and Other		0.1
Income Tax Expense		(0.1)
Third Quarter of 2005 Net Income		$ 2.2

Gross margin decreased $0.2 million primarily due to variances in the estimated tax expense component of billed revenues.

The increase in Other Operation and Maintenance expenses resulted from increased unplanned outages and the related costs compared to prior year.

Taxes Other Than Income Taxes decreased due to a $1 million decline in real and personal property tax expense. The decrease reflects an unfavorable adjustment made in 2004 for actual tax expense related to a prior year.

Income Taxes

The effective tax rates for the third quarter of 2005 and 2004 were 1.0% and (2.6)%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is primarily due to amortization of investment tax credits, flow-through of book versus tax temporary differences, state income taxes and federal income tax adjustments. The change in the effective tax rate is primarily due to federal income tax adjustments and changes in various permanent and flow-through temporary differences.

Nine Months Ended September 30, 2005 Compared to Nine Months Ended September 30, 2004

Reconciliation of Nine Months Ended September 30, 2004 to
Nine Months Ended September 30, 2005 Net Income
(in millions)

Nine Months Ended September 30, 2004 Net Income		$ 5.7
Change in Gross Margin:		
Wholesale Sales		(2.1)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	3.0	
Depreciation and Amortization	(0.4)	
Taxes Other Than Income Taxes	0.8	
Nonoperating Income and Expenses, Net	0.1	
Total Change in Operating Expenses and Other		3.5
Income Tax Expense		(0.3)
Nine Months Ended September 30, 2005 Net Income		$ 6.8

Gross margin decreased $2.1 million primarily due to a decrease in billed operation and maintenance expense partially offset by the impact of the higher percentage of plant assets in service on return on capital. Plant assets in service increased with the completion of the NO_x burner installation in 2004. Gross margin fluctuates consistent with operation and maintenance expense in accordance with the unit power agreements.

The decrease in Other Operation and Maintenance expenses resulted from decreased outages and the related costs compared to prior year. In 2004, Rockport Plant Unit 2 was shut down for planned boiler inspection and repairs from early February through early April.

Depreciation and Amortization increased reflecting increased depreciable generating plant.

The decrease in Taxes Other Than Income Taxes reflects decreased real and personal property taxes of $0.8 million reflecting the 2004 adjustment discussed above.

Income Taxes

The effective tax rates for the nine months ended September 2005 and 2004 were (2.2)% and (8.9)%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is primarily due to amortization of investment tax credits, flow-through of book versus tax temporary differences, state income taxes and federal income tax adjustments. The change in the effective tax rate is primarily due to federal income tax adjustments and changes in various permanent and flow-through temporary differences.

Off-Balance Sheet Arrangement

In prior years, we entered into an off-balance sheet arrangement for the lease of Rockport Plant Unit 2. Our current policy restricts the use of off-balance sheet financing entities or structures to traditional operating lease arrangements. Our off-balance sheet arrangement has not changed significantly since year-end. For complete information on our off-balance sheet arrangement see “Off-balance Sheet Arrangements” in the “Management’s Narrative Financial Discussion and Analysis” section of our 2004 Annual Report.

Summary Obligation Information

A summary of our contractual obligations is included in our 2004 Annual Report and has not changed significantly from year-end.

Significant Factors

See the “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” section for additional discussion of factors relevant to us.

Critical Accounting Estimates

See “Critical Accounting Estimates” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” in the 2004 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets and the impact of new accounting pronouncements.

AEP GENERATING COMPANY
CONDENSED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2005 and 2004
(Unaudited)
(in thousands)

	Three Months Ended		Nine Months Ended	
	2005	2004	2005	2004
OPERATING REVENUES	$ 69,640	$ 65,303	$ 201,268	$ 176,933
OPERATING EXPENSES				
Fuel for Electric Generation	37,403	32,857	105,771	79,291
Rent - Rockport Plant Unit 2	17,070	17,070	51,212	51,212
Other Operation	2,759	2,473	8,219	7,628
Maintenance	2,421	1,835	6,411	10,025
Depreciation and Amortization	5,956	5,941	17,901	17,447
Taxes Other Than Income Taxes	1,074	2,070	3,149	3,956
Income Taxes	908	843	2,510	2,240
TOTAL	67,591	63,089	195,173	171,799
OPERATING INCOME	2,049	2,214	6,095	5,134
Nonoperating Income	-	14	84	43
Nonoperating Expenses	44	86	157	235
Nonoperating Income Tax Credit	886	905	2,654	2,709
Interest Charges	652	643	1,848	1,914
NET INCOME	$ 2,239	$ 2,404	$ 6,828	$ 5,737

CONDENSED STATEMENTS OF RETAINED EARNINGS
For the Three and Nine Months Ended September 30, 2005 and 2004
(Unaudited)
(in thousands)

	Three Months Ended		Nine Months Ended	
	2005	2004	2005	2004
BALANCE AT BEGINNING OF PERIOD	$ 26,947	$ 22,251	$ 24,237	$ 21,441
Net Income	2,239	2,404	6,828	5,737

Cash Dividends Declared	3,015	1,262	4,894	3,785
BALANCE AT END OF PERIOD	$ 26,171	$ 23,393	$ 26,171	$ 23,393

The common stock of AEGCo is wholly-owned by AEP.

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

AEP GENERATING COMPANY
CONDENSED BALANCE SHEETS
ASSETS
September 30, 2005 and December 31, 2004
(Unaudited)
(in thousands)

	2005	2004
ELECTRIC UTILITY PLANT		
Production	$ 681,097	$ 681,254
General	2,202	3,739
Construction Work in Progress	12,538	7,729
Total	695,837	692,722
Accumulated Depreciation and Amortization	378,645	368,484
TOTAL - NET	317,192	324,238
OTHER PROPERTY AND INVESTMENTS		
Nonutility Property, Net	119	119
CURRENT ASSETS		
Accounts Receivable - Affiliated Companies	25,547	23,078
Fuel	11,190	16,404
Materials and Supplies	6,898	5,962
Prepayments	17	-
TOTAL	43,652	45,444
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
Unamortized Loss on Reacquired Debt	4,318	4,496
Asset Retirement Obligations	1,264	1,117
Deferred Property Taxes	1,567	557
Other Deferred Charges	406	422
TOTAL	7,555	6,592
TOTAL ASSETS	$ 368,518	$ 376,393

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

AEP GENERATING COMPANY
CONDENSED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
September 30, 2005 and December 31, 2004
(Unaudited)

	2005	2004
CAPITALIZATION	(in thousands)	
Common Shareholder's Equity:		
Common Stock - $1,000 par value per share:		
Authorized and Outstanding - 1,000 shares	$ 1,000	$ 1,000
Paid-in Capital	23,434	23,434
Retained Earnings	26,171	24,237
Total Common Shareholder's Equity	50,605	48,671
Long-term Debt	-	44,820
TOTAL	50,605	93,491
CURRENT LIABILITIES		
Long-term Debt Due Within One Year	44,826	-
Advances from Affiliates	11,314	26,915
Accounts Payable:		
General	456	443
Affiliated Companies	16,704	17,905
Taxes Accrued	5,824	8,806
Interest Accrued	456	911
Obligations Under Capital Leases	293	210
Rent Accrued - Rockport Plant Unit 2	23,427	4,963
Other	82	73
TOTAL	103,382	60,226
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	22,296	24,762
Regulatory Liabilities:		
Asset Removal Costs	27,693	25,428
Deferred Investment Tax Credits	43,749	46,250
SFAS 109 Regulatory Liability, Net	11,779	12,852
Deferred Gain on Sale and Leaseback - Rockport Plant Unit 2	95,726	99,904
Obligations Under Capital Leases	12,000	12,264
Asset Retirement Obligations	1,288	1,216
TOTAL	214,531	222,676

Commitments and Contingencies (Note 5)

TOTAL CAPITALIZATION AND LIABILITIES	$ 368,518	$ 376,393

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

AEP GENERATING COMPANY
CONDENSED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2005 and 2004
(Unaudited)
(in thousands)

	2005	2004
OPERATING ACTIVITIES		
Net Income	$ 6,828	$ 5,737
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Depreciation and Amortization	17,901	17,447
Deferred Income Taxes	(3,539)	(1,987)
Deferred Investment Tax Credits	(2,501)	(2,502)
Deferred Property Taxes	(1,010)	(842)
Amortization of Deferred Gain on Sale and Leaseback - Rockport Plant Unit 2	(4,178)	(4,178)
Change in Other Noncurrent Assets	(1,767)	2,415
Change in Other Noncurrent Liabilities	2,079	(2,362)
Changes in Components of Working Capital:		
Accounts Receivable	(2,469)	2,587
Fuel, Materials and Supplies	4,278	947
Accounts Payable	(1,188)	(2,875)
Taxes Accrued	(2,982)	3,969
Rent Accrued - Rockport Plant Unit 2	18,464	18,464
Other Current Assets	(17)	(11)
Other Current Liabilities	(363)	(372)
Net Cash Flows From Operating Activities	29,536	36,437
INVESTING ACTIVITIES		
Construction Expenditures	(9,041)	(11,257)
Net Cash Flows Used For Investing Activities	(9,041)	(11,257)
FINANCING ACTIVITIES		
Changes in Advances to/from Affiliates, Net	(15,601)	(21,395)
Dividends Paid	(4,894)	(3,785)
Net Cash Flows Used For Financing Activities	(20,495)	(25,180)
Net Increase in Cash and Cash Equivalents	-	-
Cash and Cash Equivalents at Beginning of Period	-	-
Cash and Cash Equivalents at End of Period	$ -	$ -

SUPPLEMENTAL DISCLOSURE:
Cash paid for interest net of capitalized amounts was $2,104,000 and $2,170,000 and for income taxes was $11,025,000 and $87,000 in 2005 and 2004, respectively. Noncash acquisitions under capital leases were $31,000 and $18,000 in 2005 and 2004, respectively.

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

AEP GENERATING COMPANY
INDEX TO CONDENSED NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The condensed notes to AEGCo's condensed financial statements are combined with the condensed notes to financial statements for other subsidiary registrants. Listed below are the condensed notes that apply to AEGCo.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS

Results of Operations

Third Quarter of 2005 Compared to Third Quarter of 2004

Reconciliation of Third Quarter of 2004 to Third Quarter of 2005 Net Income
(in millions)

Third Quarter of 2004 Net Income		$ 43
Changes in Gross Margin:		
Texas Supply	(48)	
Texas Wires	9	
Off-system Sales	3	
Transmission Revenues	(3)	
Other Revenues	9	
Total Change in Gross Margin		(30)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	11	
Depreciation and Amortization	(5)	
Taxes Other Than Income Taxes	1	
Carrying Costs on Stranded Cost Recovery	15	
Nonoperating Income and Expenses, Net	5	
Interest Charges	4	
Total Change in Operating Expenses and Other		31
Income Tax Expense		(4)
Third Quarter of 2005 Net Income		$ 40

Net Income decreased $3 million in the third quarter of 2005. The key drivers of the decrease were a decrease in gross margin of $30 million, offset by Carrying Costs on Stranded Cost Recovery of $15 million and a decrease in Other Operation and Maintenance of $11 million.

The major components of our change in gross margin, defined as revenues net of related fuel and purchased power, were as follows:

- Texas Supply margins decreased $48 million primarily due to a $163 million decrease in revenue from the expiration of the supply contract with our largest REP customer; lower capacity sales of $7 million due to the sale of certain generation plants; a $2 million decrease of ERCOT Reliability-Must Run (RMR) sales; and decreased margins of $3 million. These decreases were partially offset by lower fuel and purchased power expense of $120 million.

- Texas Wires revenues increased $9 million primarily due to an increase in sales volumes of 4% resulting partly from a 14% increase in cooling degree days.
- Margins from Off-system Sales increased $3 million primarily due to favorable optimization activity.
- Other Revenues increased $9 million primarily due to the reclassification of third party construction project revenues discussed below in Other Items.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses decreased $11 million primarily due to a $14 million decrease in power plant operations and maintenance due to the sale of certain generation plants along with a $5 million decrease in administrative and general expense primarily related to employee costs. These decreases were partially offset by $10 million of increased third party construction-related expense recorded in operations as discussed below in Other Items.
- Depreciation and Amortization expense increased $5 million primarily due to the recovery and amortization of securitized transition assets.
- Taxes Other Than Income Taxes decreased $1 million primarily due to lower property-related taxes as a result of the sale of certain generation plants.
- Carrying Costs on Stranded Cost Recovery of $15 million were recorded in the third quarter of 2005. There were no carrying Costs recorded prior to December 2004. (See the "TCC Carrying Costs on Net True-up Regulatory Assets" section of Note 4)
- Nonoperating Income and Expenses, Net increased $5 million primarily due to the accrual of interest income as a result of a Texas Appeals Court Order. (See the "TCC Excess Earnings" section of Note 4)
- Interest Charges decreased $4 million primarily due to lower long-term debt outstanding and lower rates.

Other Items:

As a result of the PUCT order discussed in Note 3, "TCC Rate Case", we implemented new transmission and distribution rates effective September 6, 2005. The effect of that implementation had only a minor effect on Net Income for the third quarter of 2005. However, as a result of the order we reclassified the margins from third party construction projects from nonoperating to operating. While this reclassification affected various line items on the Statements of Income, it had no effect on Net Income.

Income Taxes

The effective tax rates for the third quarter of 2005 and 2004 were 34.3% and 28.0%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to permanent differences, amortization of investment tax credits, consolidated tax savings from Parent, state income taxes and federal income tax adjustments. The change in the effective tax rate for the comparative period is primarily due to consolidated tax savings from Parent and federal income tax adjustments.

<u>Nine Months Ended September 30, 2005 Compared to Nine Months Ended September 30, 2004</u>

Reconciliation of Nine Months Ended September 30, 2004 to Nine Months Ended September 30, 2005 Net Income (in millions)

Nine Months Ended September 30, 2004 Net Income		$ 72
Changes in Gross Margin:		
Texas Supply	(84)	
Texas Wires	21	
Off-system Sales	1	
Transmission Revenues	(4)	
Other Revenues	(2)	
Total Change in Gross Margin		(68)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	41	
Depreciation and Amortization	(12)	
Taxes Other Than Income Taxes	3	
Carrying Costs on Stranded Cost Recovery	30	
Nonoperating Income and Expenses, Net	(1)	
Interest Charges	10	
Total Change in Operating Expenses and Other		71
Income Tax Expense		(5)
Nine Months ended September 30, 2005 Net Income		$ 70

Net Income decreased $2 million for the nine months ended September 30, 2005 compared to the nine months ended September 30, 2004. The key drivers of the decrease were a decrease in gross margin of $68 million, offset by a decrease in Other Operation and Maintenance of $41 million and an increase of $30 million in Carrying Costs on Stranded Cost Recovery.

The major components of our change in gross margin, defined as revenues net of related fuel and purchased power, were as follows:

- Texas Supply margins decreased $84 million primarily due to a $395 million decrease in revenue resulting from the expiration of the supply contract with our largest REP customer; lower capacity sales of $24 million due to the sale of certain generation plants; loss of ERCOT RMR revenue of $18 million; and decreased margins of $4 million. These decreases were partially offset by lower fuel and purchased power expense of $284 million and a decrease in the provision for refund of $62 million due to the 2004 final fuel reconciliation true-up.
- Texas Wires revenue increased $21 million primarily due to an increase in sales volumes of 4% resulting primarily from a 12% increase in degree days.
- Transmission Revenues decreased $4 million primarily due to lower ERCOT revenue.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses decreased $41 million primarily due to a $23 million decrease in power plant operations, a $14 million decrease in power plant maintenance both due to the sale of certain generation plants, and a $10 million decrease in administrative and general expense primarily related to employee costs. These decreases were partially offset by $10 million of nonutility construction-related expense recorded in operations as discussed below in Other Items and slightly higher distribution-related expenses.
- Depreciation and Amortization expense increased $12 million primarily related to the recovery and amortization of securitized transition assets.
- Carrying Costs on Stranded Cost Recovery increased $30 million. Carrying Costs on Stranded Cost Recovery of $57 million were recorded in the first nine months of 2005, offset by an adjustment of $27 million for prior years recorded in the first quarter. The adjustment related to a nonaffiliated utility's securitization proceeding in which the PUCT issued an order in March 2005 that resulted in a reduction in the nonaffiliated utility's carrying costs based on a methodology detailed in the order for calculating a cost-of-money benefit related to accumulated deferred federal income taxes on net stranded cost and other true-up items retroactively applied to January 1, 2004.
- Interest Charges decreased $10 million primarily due to lower long-term debt outstanding and lower rates.

Other Items:

As a result of the PUCT order discussed in Note 3, "TCC Rate Case", we implemented new transmission and distribution rates effective September 6, 2005. The effect of that implementation had only a minor effect on Net Income for the nine months ended September 30, 2005. However, as a result of the order we reclassified the margins from third party construction projects from nonoperating to operating. While this reclassification affected various line items on the Statements of Income, it had no effect on Net Income.

Income Taxes

The effective tax rates for the nine months ended September 2005 and 2004 were 28.6% and 24.3%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to permanent differences, amortization of investment tax credits, consolidated tax savings from Parent, state income taxes and federal income tax adjustments. The increase in the effective tax rate for the comparative period is primarily due to consolidated tax savings from Parent and amortization of investment tax credits, offset in part by state income taxes.

Financial Condition

Credit Ratings

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

	Moody's	S&P	Fitch
First Mortgage Bonds	Baa1	BBB	A

Senior Unsecured Debt	Baa2	BBB	A-

Cash Flow

Cash flows for the nine months ended September 30, 2005 and 2004 were as follows:

	2005	2004
	(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ -	$ 760
Cash Flows From (Used For):		
Operating Activities	(100,333)	192,501
Investing Activities	298,047	259,028
Financing Activities	(197,711)	(450,529)
Net Increase in Cash and Cash Equivalents	3	1,000
Cash and Cash Equivalents at End of Period	$ 3	$ 1,760

Operating Activities

Our Net Cash Flows Used For Operating Activities were $100 million for the first nine months of 2005. We produced income of $70 million during the period including noncash expense items of $105 million for Depreciation and Amortization and $(63) million for Deferred Income Taxes. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in these asset and liability accounts relates to a number of items; the most significant are decreases in Taxes Accrued. Taxes Accrued decreased $111 million primarily as a result of taxes remitted to the government related to prior year and current year tax accruals.

Our Net Cash Flows From Operating Activities were $193 million for the first nine months of 2004. We produced income of $72 million during the period including noncash expense items of $93 million for Depreciation and Amortization, $60 million for Over/Under Fuel Recovery and $(121) million for Deferred Income Taxes. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The activity in these asset and liability accounts relates to a number of items; the most significant are increases in Taxes Accrued. Taxes Accrued increased $147 million primarily due to taxes that were accrued during the first nine months of 2004 in excess of the amount remitted to the government.

Investing Activities

Net Cash Flows From Investing Activities were $298 million in 2005 primarily due to $314 million of net proceeds from the sale of STP and a reduction of Other Cash Deposits, Net primarily for the retirement of defeased first mortgage bonds of $66 million. Also, cash flows used for Construction Expenditures of $109 million related to projects for transmission and distribution service reliability. For the remainder of 2005, we expect our Construction Expenditures to be approximately $100 million.

Net Cash Flows From Investing Activities were $259 million in 2004 primarily due to $425 million of net proceeds from the sale of certain generation plants, offset in part by cash deposits of $96 million for future long-term debt retirements and Construction Expenditures of $72 million related to projects for transmission and distribution service reliability.

Financing Activities

Net Cash Flows Used For Financing Activities of $198 million in 2005 were primarily due to the payments of dividends of $150 million and the retirement of long-term debt of $486 million, including $66 million of bonds that were defeased in 2004. This was partially offset by an issuance of new debt of $427 million, including $150 million of affiliated long-term debt.

Net Cash Flows Used For Financing Activities of $451 million in 2004 were primarily due to the retirement of $191 million of long-term debt, increased lending to the Utility Money Pool and payment of dividends.

Financing Activity

Long-term debt issuances and retirements during the first nine months of 2005 were:

Issuances

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in thousands)	(%)	
Installment Purchase Contract	$ 161,700	Variable	2030
Installment Purchase Contract	120,265	Variable	2028
Notes Payable - Affiliated	150,000	4.58	2007

Retirements

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in thousands)	(%)	
Senior Unsecured Notes Payable	$ 150,000	3.00	2005
Senior Unsecured Notes Payable	100,000	Variable	2005
Securitization Bonds	29,386	3.54	2005
Securitization Bonds	20,593	5.01	2008
First Mortgage Bonds	65,763	6.625	2005
Installment Purchase Contract	120,265	6.00	2028

Liquidity

We have solid investment grade ratings, which provide us ready access to capital markets in order to issue new debt, refinance short-term debt or refinance long-term debt maturities. In addition, we participate in the Utility Money Pool, which provides access to AEP's liquidity.

Summary Obligation Information

A summary of our contractual obligations is included in our 2004 Annual Report and has not changed significantly from year-end other than the issuances and retirements disclosed above.

Significant Factors

Texas Restructuring

The principal remaining component of the stranded cost recovery process in Texas is the PUCT's determination and approval of our net stranded generation costs and other recoverable true-up items including carrying costs in our true-up filing. The PUCT approved our request to file our True-up Proceeding after the sales of our interest in STP, with only the ownership interest in Oklaunion remaining to be settled. On May 19, 2005, the sales of our interest in STP closed. On May 27, 2005, we filed our true-up request seeking recovery of $2.4 billion of net stranded costs and other true-up items which we believe the Texas Restructuring Legislation allows. Our request includes unrecorded equity carrying costs through May 27, 2005, all future carrying costs through September 2005 and amounts for stranded costs that we have previously written off (principally, a $238 million provision for a probable depreciation adjustment recorded in December 2004 based on a methodology approved by the PUCT in a nonaffiliated utility's true-up order). The PUCT hearing concluded on October 4, 2005. It is anticipated that the PUCT will issue a final order in the fourth quarter of 2005.

We continue to accrue carrying costs on our net true-up regulatory asset at the embedded 8.12% debt component rate and will continue to do so until we recover our approved net true-up regulatory asset. In a nonaffiliated utility's securitization proceeding, the PUCT issued an order in March 2005 that resulted in a reduction in its carrying costs based on an assumed cost-of-money benefit for accumulated deferred federal income taxes retroactively applied to January 1, 2004. In the first nine months of 2005, we began to accrue carrying costs based on this order. Through September 30, 2005, we have computed carrying costs of $509 million, of which we have recognized $332 million to-date. The equity component of the carrying costs, which totals $177 million through September 30, 2005, will be recognized in income as collected.

In our True-up Proceeding, parties have recommended that the PUCT reduce our carrying cost rate to an amount that ranged from 7.5% to the combined rate that was settled upon in our wires rate proceeding which included a cost of debt of 5.7%. If the PUCT ultimately determines that a lower rate should be used to calculate carrying costs on our stranded cost balance, a portion of carrying costs previously recorded would have to be reversed and would have an adverse impact on future results of operations and cash flows. Based upon a range of debt rates from 7.5% to 5.7%, through September 30, 2005, such reversal would range from $28 million to $107 million, of which $6 million to $22 million would apply to amounts accrued in 2005.

When the True-up Proceeding is complete, we intend to file to recover the PUCT-approved net stranded generation costs and other true-up amounts, plus appropriate carrying costs, through a nonbypassable competition transition charge in the regulated transmission and distribution (T&D) rates and through an additional transition charge for amounts that can be recovered through the sale of securitization bonds.

We believe that our filed request for recovery of $2.4 billion of net stranded costs and other true-up items, inclusive of carrying costs, is recoverable under the Texas Restructuring Legislation and that our $1.6 billion recorded net true-up regulatory asset, inclusive of carrying costs at September 30, 2005, is probable of recovery at this time. However, other parties have contended that all or material amounts of our net stranded costs and/or wholesale capacity auction true-up amounts should not be recovered. To the extent decisions of the PUCT in our True-up Proceeding differ from our interpretation and application of the Texas Restructuring Legislation and our evaluation of other true-up orders of nonaffiliated utilities, additional provisions for material disallowances and reductions of the net true-up regulatory asset, including recorded carrying costs, are possible. Such disallowances would have a material adverse effect on future results of operations, cash flows and possibly financial condition.

See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section for additional discussion of factors relevant to us.

Critical Accounting Estimates

See "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 2004 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, the accounting for pension and other postretirement benefits and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

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

MTM Risk Management Contract Net Assets

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

MTM Risk Management Contract Net Assets
Nine Months Ended September 30, 2005
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2004	$	9,701
(Gain) Loss from Contracts Realized/Settled During the Period (a)		(3,946)
Fair Value of New Contracts When Entered During the Period (b)		74
Net Option Premiums Paid/(Received) (c)		-
Change in Fair Value Due to Valuation Methodology Changes		-
Changes in Fair Value of Risk Management Contracts (d)		5,011
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (e)		-
Total MTM Risk Management Contract Net Assets		10,840
Net Cash Flow Hedge Contracts (f)		(3,507)
Total MTM Risk Management Contract Net Assets at September 30, 2005	$	7,333

(a) "(Gain) Loss from Contracts Realized/Settled During the Period" includes realized risk management contracts and related derivatives that settled during 2005 where we entered into the contract prior to 2005.

(b) "Fair Value of New Contracts When Entered During the Period" represents the fair value at inception of long-term contracts entered into with customers during 2005. Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.

(c) "Net Option Premiums Paid/(Received)" reflects the net option premiums paid/(received) as they relate to unexercised and unexpired option contracts that were entered in 2005.

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

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

(f) "Net Cash Flow Hedge Contracts" (pretax) are discussed below in Accumulated Other Comprehensive Income (Loss).

Reconciliation of MTM Risk Management Contracts to
Condensed Consolidated Balance Sheets
As of September 30, 2005
(in thousands)

	MTM Risk Management Contracts (a)	Cash Flow Hedges	Total (b)
Current Assets	$ 32,493	$ 92	$ 32,585
Noncurrent Assets	19,433	101	19,534
Total MTM Derivative Contract Assets	51,926	193	52,119
Current Liabilities	(28,486)	(3,592)	(32,078)
Noncurrent Liabilities	(12,600)	(108)	(12,708)
Total MTM Derivative Contract Liabilities	(41,086)	(3,700)	(44,786)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 10,840	$ (3,507)	$ 7,333

(a) Does not include Cash Flow Hedges.

(b) Represents amount of total MTM derivative contracts recorded within Risk Management Assets, Long-term Risk Management Assets, Risk Management Liabilities and Long-term Risk Management Liabilities on our Condensed Consolidated Balance Sheets.

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

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

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

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

Fair Value of Contracts as of September 30, 2005
(in thousands)

	Remainder of 2005	2006	2007	2008	2009	After 2009	Total (c)
Prices Actively Quoted - Exchange Traded Contracts	$ (625)	$ 3,007	$ 253	$ 139	$ -	$ -	$ 2,774
Prices Provided by Other External Sources - OTC Broker Quotes (a)	4,678	1,641	3,723	1,389	-	-	11,431
Prices Based on Models and Other Valuation Methods (b)	(623)	(3,523)	(2,528)	392	1,390	1,527	(3,365)
Total	$ 3,430	$ 1,125	$ 1,448	$1,920	$1,390	$1,527	$10,840

(a) "Prices Provided by Other External Sources - OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.
(b) "Prices Based on Models and Other Valuation Methods" is in absence of pricing information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity is limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.
(c) Amounts exclude Cash Flow Hedges.

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

We are exposed to market fluctuations in energy commodity prices impacting our power operations. We monitor these risks on our future operations and may employ various commodity instruments and cash flow hedges to mitigate the impact of these fluctuations on the future cash flows from assets. We do not hedge all commodity price risk.

The table provides detail on designated, effective cash flow hedges included in the Condensed Consolidated Balance Sheets. The data in the table indicates the magnitude of cash flow hedges we have in place. Only contracts designated as cash flow hedges are recorded in AOCI; therefore, economic hedge contracts which are not designated as effective cash flow hedges are marked-to-market and are included in the previous risk management tables.

Total Accumulated Other Comprehensive Income (Loss) Activity
Nine Months Ended September 30, 2005
(in thousands)

	Power
Beginning Balance December 31, 2004	$ 657
Changes in Fair Value (a)	(2,871)

Reclassifications from AOCI to Net Income (b)	(150)
Ending Balance September 30, 2005	$ (2,364)

(a) "Changes in Fair Value" shows changes in the fair value of derivatives designated as cash flow hedges during the reporting period that are not yet settled at September 30, 2005. Amounts are reported net of related income taxes.

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

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $2,358 thousand loss.

Credit Risk

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

VaR Associated with Management Contracts

The following table shows the end, high, average, and low market risk as measured by VaR for the period indicated:

Nine Months Ended September 30, 2005 (in thousands)				Twelve Months Ended December 31, 2004 (in thousands)			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$220	$301	$142	$76	$157	$511	$220	$75

VaR Associated with Debt Outstanding

The risk of potential loss in fair value attributable to our exposure to interest rates, primarily related to long-term debt with fixed interest rates, was $93 million and $120 million at September 30, 2005 and December 31, 2004, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period. Therefore, a near term change in interest rates should not negatively affect our results of operation or consolidated financial position.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2005 and 2004
(Unaudited)
(in thousands)

	Three Months Ended		Nine Months Ended	
	2005	**2004**	**2005**	**2004**
OPERATING REVENUES				
Electric Generation, Transmission and Distribution	$ 202,993	$ 347,013	$ 569,980	$ 872,924
Sales to AEP Affiliates	2,528	7,596	12,794	38,622
TOTAL	205,521	354,609	582,774	911,546
OPERATING EXPENSES				
Fuel for Electric Generation	1,892	6,967	11,979	50,879
Fuel from Affiliates for Electric Generation	24	1,707	68	101,883
Purchased Electricity for Resale	1,691	114,371	27,057	140,925
Purchased Electricity from AEP Affiliates	-	54	-	6,065
Other Operation	66,661	74,780	199,870	228,287
Maintenance	8,782	12,215	38,254	51,328
Depreciation and Amortization	40,342	34,884	105,062	92,860
Taxes Other Than Income Taxes	22,828	23,814	66,282	69,028
Income Taxes	13,748	18,027	13,897	23,645
TOTAL	155,968	286,819	462,469	764,900
OPERATING INCOME	49,553	67,790	120,305	146,646
Carrying Costs on Stranded Cost Recovery	15,349	-	30,146	-
Nonoperating Income	6,081	6,783	40,637	30,946
Nonoperating Expenses (Credit)	(2,253)	3,628	21,871	11,384
Nonoperating Income Tax Expense (Credit)	7,386	(1,336)	14,141	(476)
Interest Charges	25,374	29,269	85,095	94,609
NET INCOME	40,476	43,012	69,981	72,075
Preferred Stock Dividend Requirements	60	60	181	181
EARNINGS APPLICABLE TO COMMON STOCK	$ 40,416	$ 42,952	$ 69,800	$ 71,894

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

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S
EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Nine Months Ended September 30, 2005 and 2004
(Unaudited)
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2003	$ 55,292	$132,606	$1,083,023	$ (61,872)	$1,209,049
Common Stock Dividends			(148,000)		(148,000)
Preferred Stock Dividends			(181)		(181)
TOTAL					1,060,868
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $2,762				(5,130)	(5,130)
Minimum Pension Liability, Net of Tax of $0				(3,471)	(3,471)
NET INCOME			72,075		72,075
TOTAL COMPREHENSIVE INCOME					63,474
SEPTEMBER 30, 2004	$ 55,292	$132,606	$1,006,917	$ (70,473)	$1,124,342
DECEMBER 31, 2004	$ 55,292	$132,606	$1,084,904	$ (4,159)	$1,268,643
Common Stock Dividends			(150,000)		(150,000)
Preferred Stock Dividends			(181)		(181)
TOTAL					1,118,462
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $1,626				(3,021)	(3,021)
Minimum Pension Liability, Net of Tax					

of $0				3,810	3,810
NET INCOME			69,981		69,981
TOTAL COMPREHENSIVE INCOME					70,770
SEPTEMBER 30, 2005	$ 55,292	$132,606	$1,004,704	$ (3,370)	$1,189,232

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2005 and December 31, 2004
(Unaudited)
(in thousands)

	2005	2004
ELECTRIC UTILITY PLANT		
Transmission	$ 810,540	$ 788,371
Distribution	1,468,549	1,433,380
General	228,307	220,435
Construction Work in Progress	84,894	50,612
Total	2,592,290	2,492,798
Accumulated Depreciation and Amortization	628,587	725,225
TOTAL - NET	1,963,703	1,767,573
OTHER PROPERTY AND INVESTMENTS		
Nonutility Property, Net	2,310	1,577
Bond Defeasance Funds	21,333	22,110
TOTAL	23,643	23,687
CURRENT ASSETS		
Cash and Cash Equivalents	3	-
Other Cash Deposits	41,679	135,132
Accounts Receivable:		
Customers	202,012	157,431
Affiliated Companies	20,750	67,860
Accrued Unbilled Revenues	30,095	21,589
Allowance for Uncollectible Accounts	(558)	(3,493)
Materials and Supplies	14,161	12,288
Risk Management Assets	32,585	14,048
Margin Deposits	11,565	1,891
Prepayments and Other Current Assets	12,516	9,151
TOTAL	364,808	415,897
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	17,467	15,236
Wholesale Capacity Auction True-Up	596,868	559,973
Unamortized Loss on Reacquired Debt	11,127	11,842
Designated for Securitization	1,309,811	1,361,299

Deferred Debt - Restructuring	10,910	11,596
Other	139,901	102,032
Securitized Transition Assets	608,178	642,384
Long-term Risk Management Assets	19,534	9,508
Prepaid Pension Obligations	110,501	109,628
Deferred Property Taxes	7,600	-
Deferred Charges	32,800	36,986
TOTAL	2,864,697	2,860,484
Assets Held for Sale - Texas Generation Plants	47,210	628,149
TOTAL ASSETS	$ 5,264,061	$ 5,695,790

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONDENSED CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
September 30, 2005 and December 31, 2004
(Unaudited)

	2005	2004
CAPITALIZATION	(in thousands)	
Common Shareholder's Equity:		
Common Stock - $25 par value per share:		
Authorized - 12,000,000 shares		
Outstanding - 2,211,678 shares	$ 55,292	$ 55,292
Paid-in Capital	132,606	132,606
Retained Earnings	1,004,704	1,084,904
Accumulated Other Comprehensive Income (Loss)	(3,370)	(4,159)
Total Common Shareholder's Equity	1,189,232	1,268,643
Cumulative Preferred Stock Not Subject to Mandatory Redemption	5,940	5,940
Total Shareholders' Equity	1,195,172	1,274,583
Long-term Debt - Nonaffiliated	1,651,178	1,541,552
Long-term Debt - Affiliated	150,000	-
TOTAL	2,996,350	2,816,135
CURRENT LIABILITIES		
Long-term Debt Due Within One Year - Nonaffiliated	52,265	365,742
Advances from Affiliates	12,021	207
Accounts Payable:		
General	67,039	109,688
Affiliated Companies	61,631	64,045
Customer Deposits	18,991	6,147
Taxes Accrued	71,613	184,014
Interest Accrued	16,732	41,227
Risk Management Liabilities	32,078	8,394
Obligations Under Capital Leases	390	412
Other	28,139	20,115
TOTAL	360,899	799,991
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	1,194,728	1,247,111
Long-term Risk Management Liabilities	12,708	4,896
Regulatory Liabilities:		
Asset Removal Costs	229,324	102,624
Deferred Investment Tax Credits	105,543	107,743
Over-recovery of Fuel Costs	209,526	211,526

Retail Clawback	61,385	61,384
Other	80,302	76,653
Obligations Under Capital Leases	424	468
Deferred Credits and Other	10,885	17,276
TOTAL	1,904,825	1,829,681
Liabilities Held for Sale - Texas Generation Plants	1,987	249,983
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$ 5,264,061	$ 5,695,790

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2005 and 2004
(Unaudited)
(in thousands)

	2005	2004
OPERATING ACTIVITIES		
Net Income	$ 69,981	$ 72,075
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Depreciation and Amortization	105,062	92,860
Accretion Expense	7,549	12,428
Deferred Income Taxes	(63,426)	(121,111)
Deferred Investment Tax Credits	(2,200)	(3,670)
Deferred Property Taxes	(7,600)	(5,959)
Pension and Postemployment Benefit Reserves	(2,631)	1,252
Mark-to-Market of Risk Management Contracts	(1,139)	3,991
Pension Contributions	(170)	(2,668)
Carrying Costs	(30,146)	-
Wholesale Capacity	769	-
Over/Under Fuel Recovery	(2,000)	60,000
(Gain)/Loss on Sale of Assets	(22)	(112)
Change in Other Noncurrent Assets	(14,115)	(1,511)
Change in Other Noncurrent Liabilities	3,269	(36,148)
Changes in Components of Working Capital:		
Accounts Receivable, Net	(4,997)	10,504
Fuel, Materials and Supplies	(1,763)	(7,495)
Accounts Payable	(28,003)	(6,139)
Taxes Accrued	(110,975)	147,251
Customer Deposits	12,844	4,772
Interest Accrued	(24,495)	(20,035)
Other Current Assets	(14,715)	(1,800)
Other Current Liabilities	8,590	(5,984)
Net Cash Flows From (Used For) Operating Activities	(100,333)	192,501
INVESTING ACTIVITIES		
Construction Expenditures	(109,372)	(71,735)
Proceeds From Sale of Assets	313,966	426,566
Change in Other Cash Deposits, Net	93,453	(74,132)
Change in Bond Defeasance Funds and Other	-	(21,671)
Net Cash Flows From Investing Activities	298,047	259,028
FINANCING ACTIVITIES		

Issuance of Long-term Debt- Nonaffiliated	276,663	-
Issuance of Long-term Debt - Affiliated	150,000	-
Retirement of Long-term Debt	(486,007)	(190,996)
Changes in Advances to/from Affiliates, Net	11,814	(111,352)
Dividends Paid on Common Stock	(150,000)	(148,000)
Dividends Paid on Cumulative Preferred Stock	(181)	(181)
Net Cash Flows Used For Financing Activities	(197,711)	(450,529)
Net Increase in Cash and Cash Equivalents	3	1,000
Cash and Cash Equivalents at Beginning of Period	-	760
Cash and Cash Equivalents at End of Period	$ 3	$ 1,760

SUPPLEMENTAL DISCLOSURE:

Cash paid (received) for interest net of capitalized amounts was $95,066,000 and $108,791,000 and for income taxes was $207,079,000 and $(1,058,000) in 2005 and 2004, respectively. Noncash capital lease acquisitions were $277,000 and $258,000 in 2005 and 2004, respectively. Construction Expenditures include the change in construction-related Accounts Payable of $6,959,000 and $(209,000) in 2005 and 2004, respectively.

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
INDEX TO CONDENSED NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The condensed notes to TCC's condensed consolidated financial statements are combined with the condensed notes to financial statements for other subsidiary registrants. Listed below are the condensed notes that apply to TCC.

AEP TEXAS NORTH COMPANY