Warenski Paul
Form 4
April 18, 2012

FORM 4

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

OMB APPROVAL

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Check this box if no longer subject to Section 16. Form 4 or Form 5 obligations may continue. *See* Instruction 1(b).

STATEMENT OF CHANGES IN BENEFICIAL OWNERSHIP OF SECURITIES

Filed pursuant to Section 16(a) of the Securities Exchange Act of 1934, Section 17(a) of the Public Utility Holding Company Act of 1935 or Section 30(h) of the Investment Company Act of 1940

(Print or Type Responses)

1. Name and Address of Reporting Person *
Warenski Paul

(Last) (First) (Middle)

C/O SERVICESOURCE INTERNATIONAL, INC., 634 2ND STREET

(Street)

SAN FRANCISCO, CA 94107

(City) (State) (Zip)

2. Issuer Name **and** Ticker or Trading Symbol
SERVICESOURCE INTERNATIONAL, INC. [SREV]

3. Date of Earliest Transaction (Month/Day/Year)
04/16/2012

4. If Amendment, Date Original Filed(Month/Day/Year)

5. Relationship of Reporting Person(s) to Issuer

(Check all applicable)

_____ Director _____ 10% Owner
__X__ Officer (give title below) _____ Other (specify below)
SVP and General Counsel

6. Individual or Joint/Group Filing(Check Applicable Line)
_X_ Form filed by One Reporting Person
___ Form filed by More than One Reporting Person

Table I - Non-Derivative Securities Acquired, Disposed of, or Beneficially Owned

1.Title of Security (Instr. 3)	2. Transaction Date (Month/Day/Year)	2A. Deemed Execution Date, if any (Month/Day/Year)	3. Transaction Code (Instr. 8)		4. Securities Acquired (A) or Disposed of (D) (Instr. 3, 4 and 5)			5. Amount of Securities Beneficially Owned Following Reported Transaction(s) (Instr. 3 and 4)	6. Ownership Form: Direct (D) or Indirect (I) (Instr. 4)	7. Nature of Indirect Beneficial Ownership (Instr. 4)
			Code	V	Amount	(A) or (D)	Price			
Common Stock	04/16/2012		M		5,000	A	$ 4.26	40,000	D	
Common Stock	04/16/2012		S (1)		5,000	D	$ 15.7531 (2)	35,000	D	

Reminder: Report on a separate line for each class of securities beneficially owned directly or indirectly.

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SEC 1474 (9-02)

number.

Table II - Derivative Securities Acquired, Disposed of, or Beneficially Owned
(*e.g.*, puts, calls, warrants, options, convertible securities)

1. Title of Derivative Security (Instr. 3)	2. Conversion or Exercise Price of Derivative Security	3. Transaction Date (Month/Day/Year)	3A. Deemed Execution Date, if any (Month/Day/Year)	4. Transaction Code (Instr. 8)		5. Number of Derivative Securities Acquired (A) or Disposed of (D) (Instr. 3, 4, and 5)		6. Date Exercisable and Expiration Date (Month/Day/Year)		7. Title and Amount of Underlying Securities (Instr. 3 and 4)		8 D S (I
				Code	V	(A)	(D)	Date Exercisable	Expiration Date	Title	Amount or Number of Shares	
Employee Stock Option (right to buy)	$ 4.26	04/16/2012		M			5,000	(3)	06/01/2014	Common Stock	5,000	

Reporting Owners

Reporting Owner Name / Address	Relationships			
	Director	10% Owner	Officer	Other
Warenski Paul C/O SERVICESOURCE INTERNATIONAL, INC. 634 2ND STREET SAN FRANCISCO, CA 94107			SVP and General Counsel	

Signatures

/s/ David C. Bernstein, by power of attorney	04/18/2012
**Signature of Reporting Person	Date

Explanation of Responses:

* If the form is filed by more than one reporting person, *see* Instruction 4(b)(v).

** Intentional misstatements or omissions of facts constitute Federal Criminal Violations. *See* 18 U.S.C. 1001 and 15 U.S.C. 78ff(a).

(1) The sale reported on this Form 4 was effected pursuant to a Rule 10b5-1 trading plan adopted by the Reporting Person on June 9, 2011.

(2) The sale price reported in column 4 of Table I represents the weighted average sale price of the shares sold ranging from $15.71 to $15.85 per share. Upon request by the Commission staff, the Issuer, or a security holder of the Issuer, the Reporting Person will provide full information regarding the number of shares sold at each separate price.

(3) Twenty-five percent of the shares subject to the option vested on May 12, 2009 and 2.083% of the shares vest monthly thereafter.

Note: File three copies of this Form, one of which must be manually signed. If space is insufficient, *see* Instruction 6 for procedure.
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In June 2006, the Industrial Energy Users - Ohio (IEU), an intervenor in the PUCO proceeding, filed a Complaint for Writ of Prohibition at the Ohio Supreme Court to prohibit the use of the PUCO's authorization by the Ohio companies to enforce the collection of the Phase 1 rates and to prohibit the PUCO from further entertaining any increase in rates for the IGCC project. The Court subsequently granted a PUCO motion to dismiss the Complaint for Writ of Prohibition.

In August 2006, IEU, Ohio Consumers' Counsel, FirstEnergy Solutions and Ohio Energy Group filed four separate appeals of the PUCO's order in the IGCC proceeding. The Ohio companies believe that the PUCO's authorization to begin collection of Phase 1 rates is lawful. The Ohio companies, however, cannot predict the outcome of these appeals. If the PUCO's order is found to be unlawful, future results of operations and cash flows will be adversely affected.

Transmission Rate Filing

In accordance with the RSPs, in December 2005, the PUCO approved the recovery of certain RTO transmission costs through separate transmission cost recovery riders for the Ohio companies. The transmission cost recovery riders are subject to an annual true-up process with over/under recovery mechanisms. In February 2006, the Ohio companies filed a request with the PUCO to incorporate all transmission costs and rates in their transmission cost recovery riders and institute a two-step increase to reflect the increases in the FERC-approved rates. In the filing, the first increase would be effective April 1, 2006 to reflect the Ohio companies' share of the loss of SECA revenues and the second increase would be effective August 1, 2006 to recover their share of the cost of the new Wyoming-Jacksons Ferry 765 kV line. In May 2006, the PUCO issued an order approving a two-step increase in the transmission cost recovery riders with over/under recovery mechanisms, effective April 1, 2006. The new tariffs were filed with the PUCO and implemented in June 2006.

In October 2006, the Ohio companies filed for initial true-ups under the transmission cost recovery riders' over/under recovery mechanisms. The filings reflect the refund of regulatory liabilities as of September 30, 2006 of $12 million and $16 million for CSPCo and OPCo, respectively, including carrying charges. These over-recoveries were reflected as part of the new transmission cost recovery rider filed to be effective January 2007. We anticipate the net effect of the new transmission cost recovery riders will result in increased cost recoveries over 2005 levels for CSPCo and OPCo of $27 million and $36 million, respectively, in 2006 and $15 million and $16 million, respectively, in 2007.

Distribution Service Reliability and Restoration Costs

In December 2003, the Ohio companies entered into a stipulation agreement regarding distribution service reliability. The stipulation agreement covered the years 2004 and 2005 and, among other features, established certain distribution service reliability measures that the Ohio companies were to meet. In July 2006, based on the staff report on service reliability and responses filed by the Ohio companies, the PUCO directed the Ohio companies to earmark $10 million for future measures to improve service reliability without recovery. The PUCO further indicated that it will determine where and how the $10 million will best be applied.

In March 2006, the Ohio companies filed an application with the PUCO to implement tariff riders to recover a portion of previously expensed incremental costs of restoring service disrupted by severe winter storms in December 2004 and January 2005. CSPCo and OPCo each requested recovery of approximately $12 million of such costs, which was approved by the PUCO in August 2006. Effective September 1, 2006, the Ohio companies implemented the storm cost recovery riders, which will continue until they have collected the authorized amounts or one year, whichever is shorter. In September 2006, the Ohio Consumers' Counsel filed a request for rehearing with the PUCO, which was denied in October 2006.

As a result of the above, in September 2006 the Ohio companies recorded regulatory assets of $14 million, favorably affecting earnings.

Ormet

Ormet Primary Aluminum Corporation and Ormet Primary Mill Products Corporation (together, Ormet) was a customer of OPCo until 2000. Beginning in 2000, at Ormet's request, the PUCO authorized a modification of the certified service territories of OPCo and South Central Power Company (SCP), a nonaffiliate, so that Ormet became a customer of SCP. SCP agreed to let Ormet access the electric generation market for the vast majority of its 520 MW load. Ormet filed a request with the PUCO to return to being served by OPCo at the industrial tariff rate. OPCo opposed the request because it would likely require the purchase of capacity and energy from the market at prices above the industrial RSP tariff rate in order to serve Ormet, as well as substantially reduce our ability to sell energy into the wholesale market at the higher market prices.

In June 2006, the PUCO found that SCP was not providing or proposing to provide physically adequate service to Ormet. In October 2006, the PUCO convened a hearing to determine if an electric supplier, other than SCP, should be authorized to serve Ormet's significant load.

Subsequent to the hearing, the Ohio companies together with Ormet, its employees' union and certain other interested parties filed a settlement agreement with the PUCO for approval. The settlement agreement provides for the reallocation of the service territories of CSPCo, OPCo and SCP so that Ormet's Hannibal, Ohio facilities are located in a joint CSPCo/OPCo certified territory effective January 1, 2007. The settlement also provides for the recovery in 2007 and 2008 by CSPCo and OPCo of the difference between $43 per MWH paid by Ormet and a to-be-determined market price submitted by management and reviewed by the PUCO. The recovery is accomplished by the amortization to income of a $57 million ($15 million for CSPCo and $42 million for OPCo) Ohio franchise tax phase-out regulatory liability recorded in 2005 and, if that is not sufficient, an increase in RSP generation rates under the additional 4% provision of the RSP. The $43 per MWH price for generation services is above the industrial RSP generation tariff but below current market prices.

Customer Choice Deferrals

As provided in stipulation agreements approved by the PUCO in 2000, the Ohio companies defer customer choice implementation costs and related carrying costs in excess of $20 million each. The agreements provide for the deferral of these costs as regulatory assets until the next distribution base rate cases. Through September 30, 2006, we incurred $97 million of such costs and deferred $48 million of such costs for probable future recovery in distribution rates. We have not recorded $9 million of equity carrying costs, which are not recognized until collected. Pursuant to the RSPs, recovery of these amounts is subject to PUCO review and is deferred until the next distribution rate filing to change rates after the December 31, 2008 end of the RSP period. We believe that the deferred customer choice implementation costs were prudently incurred to implement customer choice in Ohio and should be recoverable in future distribution rates. If the PUCO determines that any of the deferred costs are unrecoverable, it would have an adverse impact on future results of operations and cash flows.

5. COMMITMENTS AND CONTINGENCIES

As discussed in the Commitments and Contingencies note within our 2005 Annual Report, we continue to be involved in various legal matters. The 2005 Annual Report should be read in conjunction with this report in order to understand the other material nuclear and operational matters without significant changes since our disclosure in the 2005 Annual Report. See disclosure below for significant matters and changes in status subsequent to the disclosure made in our 2005 Annual Report.

ENVIRONMENTAL

Federal EPA Complaint and Notice of Violation

The Federal EPA and a number of states alleged that APCo, CSPCo, I&M, OPCo and other nonaffiliated utilities, including the Tennessee Valley Authority, Alabama Power Company, Cincinnati Gas & Electric Company, Ohio Edison Company, Southern Indiana Gas & Electric Company, Illinois Power Company, Tampa Electric Company, Virginia Electric Power Company and Duke Energy, modified certain units at coal-fired generating plants in violation of the NSR requirements of the CAA. The Federal EPA filed its complaints against our subsidiaries in U.S. District Court for the Southern District of Ohio. The court also consolidated a separate lawsuit, initiated by certain special interest groups, with the Federal EPA case. The alleged modifications occurred at our generating units over a 20-year period. A bench trial on the liability issues was held during July 2005. Briefing has concluded. In June 2006, the judge stayed the liability decision pending the issuance of a decision by the U.S. Supreme Court in the Duke Energy case. A bench trial on remedy issues, if necessary, is scheduled to begin four months after the U.S. Supreme Court decision is issued.

Under the CAA, if a plant undertakes a major modification that directly results in an emissions increase, permitting requirements might be triggered and the plant may be required to install additional pollution control technology. This requirement does not apply to activities such as routine maintenance, replacement of degraded equipment or failed components or other repairs needed for the reliable, safe and efficient operation of the plant. The CAA authorizes civil penalties of up to $27,500 ($32,500 after March 15, 2004) per day per violation at each generating unit. In 2001, the District Court ruled claims for civil penalties based on activities that occurred more than five years before the filing date of the complaints cannot be imposed. There is no time limit on claims for injunctive relief.

The Federal EPA and eight northeastern states each filed an additional complaint containing additional allegations against the Amos and Conesville plants. APCo and CSPCo filed an answer to the northeastern states' complaint and the Federal EPA's complaint, denying the allegations and stating their defenses. Cases are also pending that could affect CSPCo's share of jointly-owned units at Beckjord, Zimmer and Stuart stations. Similar cases have been filed against other nonaffiliated utilities, including Allegheny Energy, Eastern Kentucky Electric Cooperative, Public Service Enterprise Group, Santee Cooper, Wisconsin Electric Power Company, Mirant, NRG Energy and Niagara Mohawk. Several of these cases were resolved through consent decrees.

Courts have reached different conclusions regarding whether the activities at issue in these cases are routine maintenance, repair or replacement, and therefore, are excluded from NSR. Similarly, courts have reached different results regarding whether the activities at issue increased emissions from the power plants. Appeals on these and other issues were filed in certain appellate courts, including a petition to appeal to the U.S. Supreme Court that was granted in one case. The Federal EPA issued a final rule that would exclude activities similar to those challenged in these cases from NSR as "routine replacements." In March 2006, the Court of Appeals for the District of Columbia Circuit issued a decision vacating the rule. The Federal EPA filed a petition for rehearing in that case, which the Court denied. The Federal EPA also recently proposed a rule that would define "emissions increases" in a way that would exclude most of the challenged activities from NSR.

We are unable to estimate the loss or range of loss related to any contingent liability we might have for civil penalties under the CAA proceedings. We are also unable to predict the timing of resolution of these matters due to the number of alleged violations and the significant number of issues yet to be determined by the Court. If we do not prevail, we believe we can recover any capital and operating costs of additional pollution control equipment that may be required through regulated rates and market prices of electricity. If we are unable to recover such costs or if material penalties are imposed, it would adversely affect future results of operations, cash flows and possibly financial condition.

SWEPCo Notice of Enforcement and Notice of Citizen Suit

In July 2004, two special interest groups, Sierra Club and Public Citizen, issued a notice of intent to commence a citizen suit under the CAA for alleged violations of various permit conditions in permits issued to several SWEPCo generating plants. In March 2005, the special interest groups filed a complaint in Federal District Court for the Eastern

District of Texas alleging violations of the CAA at the Welsh Plant. SWEPCo filed a response to the complaint in May 2005. Other preliminary motions have been filed and are pending before the Court.

In July 2004, the Texas Commission on Environmental Quality (TCEQ) issued a Notice of Enforcement to SWEPCo relating to the Welsh Plant containing a summary of findings resulting from a compliance investigation at the plant. In April 2005, TCEQ issued an Executive Director's Preliminary Report and Petition recommending the entry of an enforcement order to undertake certain corrective actions and assessing an administrative penalty of approximately $228 thousand against SWEPCo based on alleged violations of certain representations regarding heat input in SWEPCo's permit application and the violations of certain recordkeeping and reporting requirements. SWEPCo responded to the preliminary report and petition in May 2005. The enforcement order contains a recommendation that would limit the heat input on each Welsh unit to the referenced heat input contained within the permit application within 10 days of the issuance of a final TCEQ order and until a permit amendment is issued. SWEPCo had previously requested a permit alteration to remove the reference to a specific heat input value for each Welsh unit.

Management is unable to predict the timing of any future action by TCEQ or the special interest groups or the effect of such actions on results of operations, financial condition or cash flows.

Carbon Dioxide (CO_2) Public Nuisance Claims

In July 2004, attorneys general from eight states and the corporation counsel for 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. That same day, the Natural Resources Defense Council, on behalf of three special interest groups, filed a similar complaint in the same court against the same defendants. The actions alleged that CO_2 emissions from the defendants' power plants constitute a public nuisance under federal common law due to impacts associated with global warming and sought injunctive relief in the form of specific emission reduction commitments from the defendants. In September 2004, the defendants, including AEP and AEPSC, filed a motion to dismiss the lawsuits. In September 2005, the lawsuits were dismissed. The trial court's dismissal was appealed to the Second Circuit Court of Appeals. Briefing and oral argument have been completed. We believe the actions are without merit and intend to defend against the claims.

Ontario Litigation

In June 2005, we, along with nineteen nonaffiliated utilities, were named as defendants in a lawsuit filed in the Superior Court of Justice in Ontario, Canada. We have not been served with the lawsuit. The time limit for serving the defendants expired, but the case has not been dismissed. The defendants are alleged to own or operate coal-fired electric generating stations in various states that, through negligence in design, management, maintenance and operation, emitted $NO_{X,}$ SO_2 and particulate matter that harmed the residents of Ontario. The lawsuit seeks class action designation and damages of approximately $49 billion, with continuing damages of $4 billion annually. The lawsuit also seeks $1 billion in punitive damages. We believe we have meritorious defenses to this action and intend to defend against it.

OPERATIONAL

Power Generation Facility and TEM Litigation

We have agreements with Juniper Capital L.P. (Juniper) under which Juniper constructed and financed a merchant power generation facility (Facility) near Plaquemine, Louisiana and leased the Facility to us. We subleased the Facility to the Dow Chemical Company (Dow). The Facility is a Dow-operated "qualifying cogeneration facility" for purposes of PURPA.

Juniper is a nonaffiliated limited partnership, formed to construct or otherwise acquire real and personal property for lease to third parties, to manage financial assets and to undertake other activities related to asset financing. Juniper arranged to finance the Facility. The Facility is collateral for Juniper's debt financing. Due to the treatment of the Facility as a financing of an owned asset, we recognized all of Juniper's funded obligations as a liability. Upon expiration of the lease, our actual cash obligation could range from $0 to $415 million based on the fair value of the assets at that time. However, if we default under the Juniper lease, our maximum cash payment could be as much as $525 million. Because we report Juniper's funded obligations totaling $525 million related to the Facility on our Condensed Consolidated Balance Sheets, the fair value of the liability for our guarantee (the $415 million payment discussed above) is not separately reported.

In August 2006, we reached an agreement with Dow to sell the Facility to them. We expect the sale to close during the fourth quarter of 2006 following receipt of federal regulatory approvals. Upon closing, we will repay our recorded $525 million lease financing obligation, which is included in Long-term Debt Due Within One Year on our Condensed Consolidated Balance Sheet at September 30, 2006. The approved sale resulted in a third quarter pretax impairment of approximately $209 million (see Note 8).

Dow uses a portion of the energy produced by the Facility and sells the excess energy. OPCo agreed to purchase up to approximately 800 MW of such excess energy from Dow for a 20-year term. Because the Facility is a major steam supply for Dow, Dow is expected to operate the Facility at certain minimum levels, and OPCo is obligated to purchase the energy generated at those minimum operating levels (approximately 270 MW). OPCo sells the purchased energy at market prices in the Entergy sub-region of the Southeastern Electric Reliability Council market.

OPCo agreed to sell up to approximately 800 MW of energy to TEM for a period of 20 years under a Power Purchase and Sale Agreement dated November 15, 2000 (PPA), at a price that is currently in excess of market. Beginning May 1, 2003, OPCo tendered replacement capacity, energy and ancillary services to TEM pursuant to the PPA that TEM rejected as nonconforming. Commercial operation for purposes of the PPA began April 2, 2004.

In September 2003, TEM and AEP separately filed declaratory judgment actions in the U.S. District Court for the Southern District of New York. We alleged that TEM breached the PPA, and we sought a determination of our rights under the PPA. TEM alleged that the PPA never became enforceable, or alternatively, that the PPA was terminated as the result of AEP's breaches. The corporate parent of TEM (SUEZ-TRACTEBEL S.A.) provided a limited guaranty.

In April 2004, OPCo gave notice to TEM that OPCo (a) was suspending performance of its obligations under the PPA; (b) would seek a declaration from the District Court that the PPA was terminated; and (c) would pursue TEM and SUEZ-TRACTEBEL S.A. under the guaranty, seeking damages and the full termination payment value of the PPA.

A bench trial was conducted in March and April 2005. In August 2005, a federal judge ruled that TEM breached the contract and awarded us damages of $123 million plus prejudgment interest. In August 2005, both parties filed motions with the trial court seeking reconsideration of the judgment. We asked the court to modify the judgment to (a) award a termination payment to us under the terms of the PPA; (b) grant our attorneys' fees; and (c) render judgment against SUEZ-TRACTEBEL S.A. on the guaranty. TEM sought reduction of the damages awarded by the court for replacement electric power products made available by OPCo under the PPA. In January 2006, the trial judge granted our motion for reconsideration concerning TEM's parent guaranty and increased our judgment against TEM to $173 million plus prejudgment interest, and denied the remaining motions for reconsideration. In March 2006, the trial judge amended the January 2006 order eliminating the additional $50 million damage award.

In September 2005, TEM posted a letter of credit for $142 million as security pending appeal of the judgment. Both parties have filed Notices of Appeal with the United States Court of Appeals for the Second Circuit. Oral argument is scheduled for December 2006. If the PPA is deemed terminated or found unenforceable by the court ultimately deciding the case, we could be adversely affected to the extent we are unable to find other purchasers of the power with similar contractual terms (if our sale of the Facility to Dow does not close) and to the extent we do not fully recover the claimed termination value damages from TEM.

Enron Bankruptcy

In connection with our 2001 acquisition of HPL, we entered into an agreement with BAM Lease Company, which granted HPL the exclusive right to use approximately 65 billion cubic feet (BCF) of cushion gas required for the normal operation of the Bammel gas storage facility. At the time of our acquisition of HPL, Bank of America (BOA) and certain other banks (the BOA Syndicate) and Enron entered into an agreement granting HPL the exclusive use of 65 BCF of cushion gas. Also at the time of our acquisition, Enron and the BOA Syndicate released HPL from all prior and future liabilities and obligations in connection with the financing arrangement.

After the Enron bankruptcy, the BOA Syndicate informed HPL of a purported default by Enron under the terms of the financing arrangement. In July 2002, the BOA Syndicate filed a lawsuit against HPL in Texas state court seeking a declaratory judgment that the BOA Syndicate has a valid and enforceable security interest in gas purportedly in the Bammel storage reservoir. In December 2003, the Texas state trial court granted partial summary judgment in favor of the BOA Syndicate. HPL appealed this decision. In August 2006, the Court of Appeals for the First District of Texas vacated the trial court's judgment and dismissed the BOA Syndicate's case. The BOA Syndicate did not seek review of this decision. In June 2004, BOA filed an amended petition in a separate lawsuit in Texas state court seeking to obtain possession of up to 55 BCF of storage gas in the Bammel storage facility or its fair value. Following an adverse decision on its motion to obtain possession of this gas, BOA voluntarily dismissed this action. In October 2004, BOA refiled this action. HPL filed a motion to have the case assigned to the judge who heard the case originally and that motion was granted. HPL intends to continue to defend against BOA's claims.

In October 2003, AEP filed a lawsuit against BOA in the United States District Court for the Southern District of Texas. BOA led a lending syndicate involving the 1997 gas monetization that Enron and its subsidiaries undertook and the leasing of the Bammel underground gas storage reservoir to HPL. The lawsuit asserts that BOA made misrepresentations and engaged in fraud to induce and promote the stock sale of HPL, that BOA directly benefited from the sale of HPL and that AEP undertook the stock purchase and entered into the Bammel storage facility lease arrangement with Enron and the cushion gas arrangement with Enron and BOA based on misrepresentations that BOA made about Enron's financial condition that BOA knew or should have known were false including that the 1997 gas monetization did not contravene or constitute a default of any federal, state, or local statute, rule, regulation, code or any law. In February 2004, BOA filed a motion to dismiss this Texas federal lawsuit. In September 2004, the Magistrate Judge issued a Recommended Decision and Order recommending that BOA's Motion to Dismiss be denied, that the five counts in the lawsuit seeking declaratory judgments involving the Bammel reservoir and the right to use and cushion gas consent agreements be transferred to the Southern District of New York and that the four counts alleging breach of contract, fraud and negligent misrepresentation proceed in the Southern District of Texas. BOA objected to the Magistrate Judge's decision. In April 2005, the Judge entered an order overruling BOA's objections, denying BOA's Motion to Dismiss and severing and transferring the declaratory judgment claims to the Southern District of New York. HPL and BOA filed motions for summary judgment in the case pending in the Southern District of New York.

In February 2004, in connection with BOA's dispute, Enron filed Notices of Rejection regarding the cushion gas exclusive right-to-use agreement and other incidental agreements. We objected to Enron's attempted rejection of these agreements and filed an adversary proceeding contesting Enron's right to reject these agreements.

In 2005, we sold our interest in HPL. We indemnified the buyer of HPL against any damages resulting from the BOA litigation up to the purchase price. The determination of the gain on sale and the recognition of the gain are dependent on the ultimate resolution of the BOA dispute and the costs, if any, associated with the resolution of this matter (see Note 8).

In June and July 2006, we held mediation discussions with BOA and Enron concerning these gas disputes. No further discussions are scheduled at this time. Although management is unable to predict the outcome of the remaining lawsuits, it is possible that their resolution could have an adverse impact on our results of operations, cash flows and financial condition.

Shareholder Lawsuits

In the fourth quarter of 2002 and the first quarter of 2003, three putative class action lawsuits were filed against AEP, certain executives and AEP's Employee Retirement Income Security Act (ERISA) Plan Administrator alleging violations of ERISA in the selection of AEP stock as an investment alternative and in the allocation of assets to AEP stock. The ERISA actions were pending in Federal District Court, Columbus, Ohio. In July 2006, the Court entered judgment denying plaintiff's motion for class certification and dismissing all claims without prejudice. In August 2006, plaintiff filed a notice of appeal to the United States Court of Appeals for the Sixth Circuit. Briefing of this appeal is scheduled for completion in December 2006.

Natural Gas Markets Lawsuits

In November 2002, the Lieutenant Governor of California filed a lawsuit in Los Angeles County California Superior Court against forty energy companies, including AEP, and two publishing companies alleging violations of California law through alleged fraudulent reporting of false natural gas price and volume information with an intent to affect the market price of natural gas and electricity. AEP was dismissed from the case. A number of similar cases were filed in California. In addition, a number of other cases have been filed in state and federal courts in several states making essentially the same allegations under federal or state laws against the same companies. In some of these cases, AEP (or a subsidiary) is among the companies named as defendants. These cases are at various pre-trial stages. Several of these cases had been transferred to the United States District Court for the District of Nevada but subsequently remanded to California state court. In April 2005, the judge in Nevada dismissed one of the remaining cases in which AEP was a defendant on the basis of the filed rate doctrine and in December 2005, the judge dismissed two additional cases on the same ground. Plaintiffs in these cases appealed the decisions. We will continue to defend each case where an AEP company is a defendant.

Cornerstone Lawsuit

In the third quarter of 2003, Cornerstone Propane Partners filed an action in the United States District Court for the Southern District of New York against forty companies, including AEP and AEPES, seeking class certification and alleging unspecified damages from claimed price manipulation of natural gas futures and options on the NYMEX from January 2000 through December 2002. Thereafter, two similar actions were filed in the same court against a number of companies, including AEP and AEPES, making essentially the same claims as Cornerstone Propane Partners and also seeking class certification. These cases were consolidated. In January 2004, plaintiffs filed an amended consolidated complaint. The defendants filed a motion to dismiss the complaint which the Court denied. In October 2005, the Court granted the plaintiffs motion for class certification. We intend to continue to defend against these claims.

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

6. GUARANTEES

There are certain immaterial liabilities recorded for guarantees in accordance with FASB Interpretation No. 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 excess of our ownership percentages. In the event any guarantee is drawn, there is no recourse to third parties unless specified below.

LETTERS OF CREDIT

We enter into standby letters of credit (LOCs) with third parties. These LOCs cover items such as gas and electricity risk management contracts, construction contracts, insurance programs, security deposits, debt service reserves and credit enhancements for issued bonds. As the parent company, we issued all of these LOCs in our ordinary course of business on behalf of our subsidiaries. At September 30, 2006, the maximum future payments for all the LOCs are approximately $34 million with maturities ranging from October 2006 to July 2007.

GUARANTEES OF THIRD-PARTY OBLIGATIONS

SWEPCo

In connection with reducing the cost of the lignite mining contract for its Henry W. Pirkey Power Plant, SWEPCo agreed, under certain conditions, to assume the capital lease obligations and term loan payments of the mining contractor, Sabine Mining Company (Sabine). If Sabine defaults under any of these agreements, SWEPCo's total future maximum payment exposure is approximately $68 million with maturity dates ranging from February 2007 to February 2012.

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provides guarantees of mine reclamation in the amount of approximately $85 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by Sabine. This guarantee ends upon depletion of reserves and final reclamation is completed. At September 30, 2006, we estimate the reserves will be depleted in 2029 with final reclamation completed by 2036. We estimate the cost for final reclamation during the period 2029 through 2036 at approximately $39 million.

INDEMNIFICATIONS AND OTHER GUARANTEES

Contracts

We enter into several 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, our exposure generally does not exceed the sale price. Prior to September 30, 2006, we entered into several sale agreements. The status of certain sales agreements is discussed in Note 8. These sale agreements include indemnifications with a maximum exposure related to the collective purchase price, which is approximately $2.1 billion (approximately $1 billion relates to the BOA litigation, see "Enron Bankruptcy" section of Note 5). There are no material liabilities recorded for any indemnifications.

Master Operating Lease

We lease certain equipment under a master operating lease. Under the lease agreement, the lessor is guaranteed receipt of up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair market value of the leased equipment is below the unamortized balance at the end of the lease term, we are committed to pay the difference between the fair market value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. At September 30, 2006, the maximum potential loss for these lease agreements was approximately $54 million ($35 million, net of tax) assuming the fair market value of the equipment is zero at the end of the lease term.

Railcar Lease

In June 2003, we entered into an agreement with BTM Capital Corporation, as lessor, to lease 875 coal-transporting aluminum railcars. The lease has an initial term of five years.

At the end of each lease term, we may (a) renew for another five-year term, not to exceed a total of twenty years, (b) purchase the railcars for the purchase price amount specified in the lease, projected at the lease inception to be the then fair market value, or (c) return the railcars and arrange a third party sale (return-and-sale option). The lease is accounted for as an operating lease. We intend to renew the lease for the full twenty years.

Under the lease agreement, the lessor is guaranteed that the sale proceeds under the return-and-sale option discussed above will equal at least the lessee obligation amount specified in the lease, which declines over the current lease term from approximately 86% to 77% of the projected fair market value of the equipment. At September 30, 2006, 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. We have other railcar lease arrangements that do not utilize this type of structure.

7. COMPANY-WIDE STAFFING AND BUDGET REVIEW

As a result of a company-wide staffing and budget review in the second quarter of 2005, we identified approximately 500 positions for elimination. Pretax severance benefits expense of $24 million and $4 million was recorded (primarily in Maintenance and Other Operation within the Utility Operations segment) in the second and third quarters of 2005, respectively.

The following table shows the accrual as of December 31, 2005 (reflected primarily in Current Liabilities - Other on our Condensed Consolidated Balance Sheets) and the activity during the first nine months of 2006, which eliminated the accrual as of June 30, 2006:

		Amount (in millions)
Accrual at December 31, 2005	$	12
Less: Total Payments		8
Less: Accrual Adjustments		4
Accrual at September 30, 2006	$	-

The favorable accrual adjustments were recorded primarily in Maintenance and Other Operation on our Condensed Consolidated Statements of Operations.

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

ACQUISITIONS

2005

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.

DISPOSITIONS

2006

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. We received an indicative offer for Bajio in September 2005, which resulted in a pretax other-than-temporary impairment charge of approximately $7 million. The impairment amount is classified in Investment Value Losses on our Condensed Consolidated Statements of Operations. We completed the sale in February 2006 for approximately $29 million with no effect on our 2006 results of operations.

2005

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

During 2005, we sold our 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. Although the assets were 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 recorded the excess of the sales price over the carrying cost of the net assets transferred as a deferred gain of $379 million as of September 30, 2006 and December 31, 2005, which is reflected in Deferred Credits and Other on our Condensed Consolidated Balance Sheets. We provided an indemnity to the purchaser in an amount up to the purchase price for damages, if any, arising from litigation with BOA and a potential resulting inability to use the cushion gas (see "Enron Bankruptcy" section of Note 5). The HPL operations did 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 and the cushion gas arrangement. In addition, we continue holding forward gas contracts, with expirations through 2011, not sold with the gas pipeline and storage assets. We manage the commodity price risk associated with these forward gas contracts to limit our price risk exposure principally by entering into equal and offsetting contracts. For the nine months ended September 30, 2006, the change in the mark-to-market value of these positions was less than $100,000.

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 and was amended through a series of agreements that AEP and Centrica entered in March 2005. Also in March 2005, we received payments related to the ESM of $45 million and $70 million for 2003 and 2004, respectively, resulting in a pretax gain of $112 million in

2005. In March 2006, we received a payment of $70 million related to the ESM for 2005. The ESM payment for 2006 is contingent on Centrica's future operating results and is contractually capped at $20 million. The payments are reflected in Gain/Loss on Disposition of Assets, Net on our Condensed Consolidated Statements of Operations.

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 classified as shown in the following table (in millions):

Three Months ended September 30, 2006 and 2005:

	SEEBOARD (a)		U.K. Generation (b)		Total	
2006 Revenue	$	-	$	-	$	-
2006 Pretax Income		-		-		-
2006 Earnings, Net of Tax		-		-		-
2005 Revenue	$	13	$	-	$	13
2005 Pretax Income		13		-		13
2005 Earnings, Net of Tax		20		2		22

Nine Months ended September 30, 2006 and 2005:

	SEEBOARD (a)		U.K. Generation(c)		Total	
2006 Revenue	$	-	$	-	$	-
2006 Pretax Income		-		9		9
2006 Earnings, Net of Tax		-		6		6
2005 Revenue (Expense)	$	13	$	(8)	$	5
2005 Pretax Income (Loss)		13		(8)		5
2005 Earnings (Loss), Net of Tax		29		(3)		26

(a) The amounts relate to purchase price true-up adjustments and tax adjustments from the sale of SEEBOARD.
(b) The amount relates to a tax adjustment from the sale.
(c) The 2006 amounts relate to a release of accrued liabilities for the London office lease and tax adjustments from the sale. Amounts in 2005 relate to purchase price true-up adjustments and tax adjustments from the sale.

There were no cash flows used for or provided by operating, investing or financing activities related to our discontinued operations for the nine months ended September 30, 2006 and 2005.

ASSETS HELD FOR SALE AND ASSET IMPAIRMENTS

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 Golden Spread Electric Cooperative, Inc. (Golden Spread), subject to a right of first refusal by the Oklahoma Municipal Power Authority and the Public Utilities Board of the City of Brownsville (the nonaffiliated co-owners). By May 2004, we received notice from the nonaffiliated co-owners 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 the nonaffiliated co-owners for the sale of TCC's 7.81% ownership of the Oklaunion Power Station. Golden Spread challenged these agreements in State District Court in Dallas County. Golden Spread alleges that the Public Utilities Board of the City of Brownsville exceeded its legal authority and that the Oklahoma Municipal Power Authority did not exercise its right of first refusal in a timely manner. Golden Spread requested that the court declare the nonaffiliated co-owners' exercise of their rights of first refusal void. The court entered a judgment in favor of Golden Spread in October 2005. TCC and the nonaffiliated co-owners filed an appeal to the Court of Appeals for the Fifth District at Dallas. In May 2006, the Court of Appeals for the Fifth District at Dallas reversed the trial court's judgment in favor of Golden Spread and held that the City of Brownsville properly exercised its right of first refusal to acquire TCC's share of Oklaunion. Golden Spread requested a rehearing in the matter, and its petition was denied. Golden Spread then appealed to the Supreme Court of Texas and in August 2006, the court requested a response from the Oklahoma Municipal Power Authority, the Public Utilities Board of the City of Brownsville and us. Responses were due October 27, 2006. We cannot predict when these issues will be resolved. We do not expect the sale to have a significant effect on the terms of the future results of operations. TCC's assets related to the Oklaunion Power Station are classified as Assets Held for Sale on our Condensed Consolidated Balance Sheets at September 30, 2006 and December 31, 2005. 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.

Power Generation Facility (Investments - Other segment)

In August 2006, we reached an agreement to sell our Plaquemine Cogeneration Facility (the Facility) to Dow Chemical Company (Dow) for $64 million. We expect the sale to close in the fourth quarter of 2006. We recorded a pretax impairment of $209 million ($136 million, net of tax) in the third quarter of 2006 based on the terms of the agreement to sell the Facility to Dow. We recorded the impairment in Asset Impairments and Other Related Charges on our Condensed Consolidated Statements of Operations. We classified the Facility's assets as Assets Held for Sale on our Condensed Consolidated Balance Sheet at September 30, 2006. The Facility does not meet the criteria for discontinued operations reporting.

In addition to the cash proceeds, the sale agreement allows us to participate in gross margin sharing on the Facility for five years. Dow will reduce an existing below-current-market long-term power supply contract with us in Texas by 50 MW, and we retain the right to any judgment paid by TEM for breaching the original PPA, as discussed in Note 5.

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.

We recognized a pretax charge of approximately $39 million in the third quarter of 2005 related to our decision to retire the units. We classified the impairment amount in Asset Impairments and Other Related Charges on our Condensed Consolidated Statements of Operations.

Assets Held for Sale at September 30, 2006 and December 31, 2005 are as follows:

September 30, 2006	Texas Plants	Power Generation Facility	Total

Assets:		(in millions)	
Other Current Assets	$ 2	$ -	$ 2
Property, Plant and Equipment, Net	44	64	108
Total Assets Held for Sale	$ 46	$ 64	$ 110

December 31, 2005	Texas Plants
Assets:	**(in millions)**
Other Current Assets	$ 1
Property, Plant and Equipment, Net	43
Total Assets Held for Sale	$ 44

9. BENEFIT PLANS

Components of Net Periodic Benefit Cost

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, 2006 and 2005:

	Pension Plans		Other Postretirement Benefit Plans	
Three Months Ended September 30, 2006 and 2005:	**2006**	**2005**	**2006**	**2005**
		(in millions)		
Service Cost	$ 23	$ 23	$ 10	$ 10
Interest Cost	57	57	26	26
Expected Return on Plan Assets	(82)	(77)	(24)	(23)
Amortization of Transition (Asset) Obligation	-	(1)	7	6
Amortization of Net Actuarial Loss	20	13	5	5
Net Periodic Benefit Cost	$ 18	$ 15	$ 24	$ 24

	Pension Plans		Other Postretirement Benefit Plans	
Nine Months Ended September 30, 2006 and 2005:	**2006**	**2005**	**2006**	**2005**
		(in millions)		
Service Cost	$ 71	$ 69	$ 30	$ 31
Interest Cost	171	169	76	79
Expected Return on Plan Assets	(248)	(232)	(70)	(68)
Amortization of Transition (Asset) Obligation	-	(1)	21	20
Amortization of Net Actuarial Loss	59	40	15	19
Net Periodic Benefit Cost	$ 53	$ 45	$ 72	$ 81

10. STOCK-BASED COMPENSATION

As previously approved by shareholder vote, the Amended and Restated American Electric Power System Long-Term Incentive Plan (the Plan) authorizes the use of 19,200,000 shares of AEP common stock for various types of stock-based compensation awards, including stock option awards, to key employees. A maximum of 9,000,000 shares may be used under this plan for full value share awards, which include performance units, restricted shares and restricted stock units. The Board of Directors and shareholders both adopted the original Plan in 2000 and the amended and restated version in 2005. We have not granted options as part of our regular stock-based compensation program since 2003. However, we have used stock options in limited circumstances totaling 149,000 options in 2004, 10,000 options in 2005 and none during 2006. The following sections provide further information regarding each type of stock-based compensation award the Board of Directors has granted.

We adopted SFAS 123R, effective January 1, 2006. See the SFAS 123 (revised 2004) “Share-Based Payment” section of Note 2 for additional information.

Stock Options

For all stock options previously granted, the exercise price equaled or exceeded the market price of AEP’s common stock on the date of grant. Historically the Board of Directors has granted stock options with a ten-year term that generally vest, subject to the participant’s continued employment, in approximately equal 1/3 increments on January 1st of the year following the first, second and third anniversary of the grant date. Compensation cost for stock options is recorded over the vesting period based on the fair value on the grant date. The Plan does not specify a maximum contractual term for stock options.

CSW maintained a stock option plan prior to the merger with AEP in 2000. Effective with the merger, all CSW stock options outstanding were converted into AEP stock options at an exchange ratio of one CSW stock option for 0.6 of an AEP stock option. The exercise price for each CSW stock option was adjusted for the exchange ratio. Outstanding CSW stock options will continue in effect until all options are exercised, cancelled, expired or forfeited. Under the CSW stock option plan, the option price was equal to the fair market value of the stock on the grant date. All CSW options fully vested upon the completion of the merger and expire 10 years after their original grant date.

The Board of Directors did not award any stock options during the nine months ended September 30, 2006.

The total fair value of stock options vested and the total intrinsic value of options exercised during the nine months ended September 30, 2006 was $3.7 million and $2.3 million, respectively. Intrinsic value is calculated as market price at exercise date less the option exercise price.

A summary of AEP stock option transactions during the nine months ended September 30, 2006 is as follows:

	Options		Weighted Average Exercise Price
	(in thousands)		
Outstanding at January 1, 2006	6,222	$	34.16
Granted	-		-
Exercised/Converted	(369)		30.17
Expired	-		-
Forfeited	(209)		41.62
Outstanding at September 30, 2006	5,644		34.15
Exercisable at September 30, 2006	5,384	$	34.41

The following table summarizes information about AEP stock options outstanding at September 30, 2006.

Options Outstanding

2006 Range of Exercise Prices	Number Exercisable (in thousands)	Weighted Average Remaining Life (in years)	Weighted Average Exercise Price	Aggregate Intrinsic Value (in thousands)
$25.73 - $27.95	1,359	5.9	$ 27.38	$ 12,220
$30.76 - $38.65	3,917	3.2	35.44	3,665
$43.79 - $49.00	368	4.6	45.43	-
	5,644	4.0	34.15	$ 15,885

The following table summarizes information about AEP stock options exercisable at September 30, 2006.

Options Exercisable

2006 Range of Exercise Prices	Number Exercisable (in thousands)	Weighted Average Remaining Life (in years)	Weighted Average Exercise Price	Aggregate Intrinsic Value (in thousands)
$25.73 - $27.95	1,158	5.7	$ 27.29	$ 10,519
$30.76 - $35.63	3,858	3.2	35.49	3,386
$43.79 - $49.00	368	4.6	45.43	-
	5,384	3.8	34.41	$ 13,905

The proceeds received from exercised stock options are included in common stock and paid-in capital. For options issued through December 31, 2005, the grant date fair value of each option award was estimated using a Black-Scholes option-pricing model with weighted average assumptions. Expected volatilities are estimated using the historical monthly volatility of our common stock for the 36-month period prior to each grant. A seven-year average expected term is also assumed. The risk-free rate is the yield for U.S. Treasury securities with a remaining life equal to the expected seven-year term of AEP stock options on the grant date.

Performance Units

Our performance units are equal in value to an equivalent number of shares of AEP common stock. The number of performance units held is multiplied by a performance score to determine the actual number of performance units realized. The performance score is determined at the end of the performance period based on performance measure(s) established for each grant at the beginning of the performance period by the Human Resources Committee of the Board of Directors (HR Committee) and can range from 0 percent to 200 percent. Performance units are typically paid in cash at the end of a three-year performance and vesting period, unless they are needed to satisfy a participant’s stock ownership requirement, in which case they are mandatorily deferred as phantom stock units (AEP Career Shares) until after the end of the participant’s AEP career. AEP Career Shares have a value equivalent to the market value of an equal number of AEP common shares and are generally paid in cash after the participant’s termination of employment. Amounts equivalent to cash dividends on both performance units and AEP Career Shares accrue as additional units. The compensation cost for performance units is recorded over the vesting period and the liability for both the performance units and AEP Career Shares is adjusted for changes in value. The vesting period of all performance units is three years.

Our Board of Directors awarded performance units and reinvested dividends on outstanding performance units and AEP Career Shares for the nine months ended September 30, 2006 as follows:

Performance Units

Awarded Units (in thousands)		864
Unit Fair Value at Grant Date	$	37.36
Vesting Period (years)		3

Performance Units and AEP Career Shares
(Reinvested Dividends Portion)

Awarded Units (in thousands)		91
Weighted Average Grant Date Fair Value	$	35.37
Vesting Period (years) (a)		3

(a) Vesting Period (years) range from 0 to 3 years. The Vesting Period of the reinvested dividends is equal to the remaining life of the related performance units and AEP Career Shares.

In January 2006, the HR Committee certified a performance score of 49% for performance units originally granted for the 2003 through 2005 performance period. As a result, 108,486 performance units were earned. Of this amount 33,296 were mandatorily deferred as AEP Career Shares, 4,360 were voluntarily deferred into the Incentive Compensation Deferral Program and the remainder were paid in cash.

The cash payouts for the nine months ended September 30, 2006 were $2.6 million for performance units and $1.0 million for AEP Career Share distributions.

The performance unit scores for all open performance periods are dependent on two equally-weighted performance measures: three-year total shareholder return measured relative to the S&P Utilities Index and three-year cumulative earnings per share measured relative to a board-approved target. The value of each performance unit earned equals the average closing price of AEP common stock for the last 20 days of the performance period.

The fair value of performance unit awards is based on the estimated performance score and the current 20-day average closing price of AEP common stock at the date of valuation.

Restricted Shares and Restricted Stock Units

Our Board of Directors granted 300,000 restricted shares to the Chairman, President and CEO on January 2, 2004 upon the commencement of his AEP employment. Of these restricted shares, 50,000 vested on January 1, 2005 and 50,000 vested on January 1, 2006. The remaining 200,000 restricted shares vest, subject to his continued employment, in approximately equal thirds on November 30, 2009, 2010 and 2011. Compensation cost is measured at fair value on the grant date and recorded over the vesting period. Fair value is determined by multiplying the number of shares granted by the grant date market price. The maximum term for these restricted shares is eight years. The Board of Directors has not granted other restricted shares. Dividends on our restricted shares are paid in cash.

Our Board of Directors may also grant restricted stock units, which generally vest, subject to the participant’s continued employment, over at least three years in approximately equal annual increments on the anniversaries of the grant date. Amounts equivalent to dividends paid on AEP shares accrue as additional restricted stock units that vest on the last vesting date associated with the underlying units. Compensation cost is measured at fair value on the grant date and recorded over the vesting period. Fair value is determined by multiplying the number of units granted by the grant date market price. The maximum contractual term of these restricted stock units is six years.

In January 2006, our Board of Directors also granted restricted stock units with performance vesting conditions to certain employees who are integral to our project to design and build an IGCC power plant. Twenty percent of these awards vest on each of the first three anniversaries of the grant date. An additional 20% vest on the date the IGCC plant achieves commercial operations. The remaining 20% vest one year after the IGCC plant achieves commercial operations, subject to achievement of plant availability targets.

Our Board of Directors awarded 47,050 restricted stock units, including units awarded for dividends, with a weighted average grant date fair value of $35.58 per unit, for the nine months ended September 30, 2006.

The total fair value and total intrinsic value of restricted shares and restricted stock units vested during the nine months ended September 30, 2006 was $3.9 million and $4.6 million, respectively.

A summary of the status of our nonvested restricted shares and restricted stock units as of September 30, 2006, and changes during the nine months ended September 30, 2006 are as follows:

Nonvested Restricted Shares and Restricted Stock Units	**Shares/Units (in thousands)**	**Weighted Average Grant Date Fair Value**
Nonvested at January 1, 2006	497	$ 32.19
Granted	47	35.58
Vested	(127)	30.56
Forfeited	(22)	35.52
Nonvested at September 30, 2006	395	32.93

The total aggregate intrinsic value of nonvested restricted shares and restricted stock units as of September 30, 2006 was $14.4 million and the weighted average remaining contractual life was 3.03 years.

Share-based Compensation Plans

Compensation cost, the actual tax benefit realized for the tax deductions from compensation cost for share-based payment arrangements recognized in income and total compensation cost capitalized in relation to the cost of an asset for the nine months ended September 30, 2006 were as follows:

Share-based Compensation Plans	**(in thousands)**
Compensation Cost for Share-based Payment Arrangements (a)	$ 16,671
Actual Tax Benefit Realized	5,835
Total Compensation Cost Capitalized	3,746

(a) Compensation cost for share-based payment arrangements is included in Maintenance and Other Operation on our Condensed Consolidated Statements of Operations.

During the nine months ended September 30, 2006, there were no significant modifications affecting any of our share-based payment arrangements.

As of September 30, 2006, there was $49.1 million of total unrecognized compensation cost related to unvested share-based compensation arrangements granted under the Plan. Unrecognized compensation cost related to the performance units and AEP Career Shares will change as the liability is revalued each period and forfeitures for all award types are realized. Our unrecognized compensation cost will be recognized over a weighted-average period of 1.57 years.

Cash received from stock options exercised and actual tax benefit realized for the tax deductions from stock options exercised during the nine months ended September 30, 2006 was $11.1 million and $0.8 million, respectively.

Our practice is to use authorized but unissued shares to fulfill share commitments for stock option exercises and restricted stock unit vesting. Although we do not currently anticipate any changes to this practice, we could use reacquired shares, shares acquired in the open market specifically for distribution under the Plan or any combination thereof for this purpose. The number of new shares issued to fulfill vesting restricted stock units is generally reduced, at the participant's election, to offset AEP's tax withholding obligation.

11. INCOME TAXES

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, we 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 we recorded a net reduction to Deferred Income Taxes on the Condensed Consolidated Balance Sheet of $48 million of which $2 million was credited to Income Tax Expense and $46 million credited to Regulatory Assets based upon the related rate-making treatment.

12. BUSINESS SEGMENTS

As outlined in our 2005 Annual Report, our business strategy and the core of our business are to focus on domestic electric utility operations. Our previous decision to no longer pursue business interests outside of our domestic core utility assets led us to divest such noncore assets. Consequently, the significance of our three Investments segments has declined.

Our segments and their related business activities are as follows:

Utility Operations

- Generation of electricity for sale to U.S. retail and wholesale customers.
- Electricity transmission and distribution in the U.S.

Investments - Gas Operations

- Gas pipeline and storage services.
- Gas marketing and risk management activities.
- We disposed of our gas pipeline and storage assets in 2005 with the sale of HPL (see "Dispositions" section of Note 8).

Investments - UK Operations

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

- We classified UK Operations as Discontinued Operations during 2003 and sold them in 2004.

Investments - Other

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

The tables below present segment income statement information for the three and nine months ended September 30, 2006 and 2005 and balance sheet information as of September 30, 2006 and December 31, 2005. These amounts include certain estimates and allocations where necessary. Prior year amounts have been reclassified to conform to the current year's presentation.

	Utility Operations	Gas Operations	UK Operations	Investments Other (in millions)	All Other (a)	Reconciling Adjustments	Consolidated
Three Months Ended September 30, 2006							
Revenues from:							
External Customers	$ 3,485	$ (47)	$ -	$ 156	$ -	$ -	$ 3,594
Other Operating Segments	(44)	51	-	4	1	(12)	-
Total Revenues	$ 3,441	$ 4	$ -	$ 160	$ 1	$ (12)	$ 3,594
Net Income (Loss)	$ 379	$ (3)	$ -	$ (109)	$ (2)	$ -	$ 265

	Utility Operations	Gas Operations	UK Operations	Investments Other (in millions)	All Other (a)	Reconciling Adjustments	Consolidated
Three Months Ended September 30, 2005							
Revenues from:							
External Customers	$ 3,152	$ 73	$ -	$ 103	$ -	$ -	$ 3,328
Other Operating Segments	85	(77)	-	3	1	(12)	-
Total Revenues	$ 3,237	$ (4)	$ -	$ 106	$ 1	$ (12)	$ 3,328
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

	Utility Operations	Gas Operations	UK Operations	Investments Other (in millions)	All Other (a)	Reconciling Adjustments	Consolidated

Nine Months Ended September 30, 2006							
Revenues from:							
External Customers	$ 9,282	$ (80)	$ -	$ 436	$ -	$ -	$ 9,638
Other Operating Segments	(73)	89	-	9	2	(27)	-
Total Revenues	$ 9,209	$ 9	$ -	$ 445	$ 2	$ (27)	$ 9,638
Income (Loss) Before Discontinued Operations	$ 904	$ (2)	$ -	$ (80)	$ (7)	$ -	$ 815
Discontinued Operations, Net of Tax	-	-	6	-	-	-	6
Net Income (Loss)	$ 904	$ (2)	$ 6	$ (80)	$ (7)	$ -	$ 821

	Utility Operations	**Gas Operations**	**Investments UK Operations**	**Other (in millions)**	**All Other (a)**	**Reconciling Adjustments**	**Consolidated**
Nine Months Ended September 30, 2005							
Revenues from:							
External Customers	$ 8,437	$ 449	$ -	$ 326	$ -	$ -	$ 9,212
Other Operating Segments	186	(167)	-	12	2	(33)	-
Total Revenues	$ 8,623	$ 282	$ -	$ 338	$ 2	$ (33)	$ 9,212
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

	Utility Operations	**Gas Operations**	**Investments UK Operations**	**Other (in millions)**	**All Other (b)**	**Reconciling Adjustments (b)**	**Consolidated**
As of September 30, 2006							
Total Property, Plant and Equipment	$ 40,397	$ 1	$ -	$ 567	$ 3	$ -	$ 40,968
Accumulated Depreciation and Amortization	15,014	-	-	130	2	-	15,146
Total Property, Plant and Equipment - Net	$ 25,383	$ 1	$ -	$ 437	$ 1	$ -	$ 25,822
Total Assets	$ 35,185	$ 591(c)	$ 639(d)	$ 72	$ 10,372	$ (10,474)	$ 36,385

Assets Held for Sale	46	-	-	64	-	-	110

		Investments					
	Utility Operations	Gas Operations	UK Operations	Other	All Other (b)	Reconciling Adjustments (b)	Consolidated
				(in millions)			
As of December 31, 2005							
Total Property, Plant and Equipment	$ 38,283	$ 2	$ -	$ 833	$ 3	$ -	$ 39,121
Accumulated Depreciation and Amortization	14,723	1	-	112	1	-	14,837
Total Property, Plant and Equipment - Net	$ 23,560	$ 1	$ -	$ 721	$ 2	$ -	$ 24,284
Total Assets	$ 34,339	$ 1,199(e)	$ 632(f)	$ 509	$ 9,463	$ (9,970)	$ 36,172
Assets Held for Sale	44	-	-	-	-	-	44

(a) All Other includes the parent company’s guarantee revenue, interest income and expense, as well as other nonallocated costs.

(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 (included in All Other) in subsidiary companies.

(c) Total Assets of $591 million for the Investments-Gas Operations segment include $321 million in affiliated accounts receivable related to the corporate borrowing program and risk management contracts that are eliminated in consolidation. The majority of the remaining $270 million in assets represents third party risk management contracts, margin deposits and accounts receivable.

(d) Total Assets of $639 million for the Investments-UK Operations segment include $625 million in affiliated accounts receivable related mainly to federal income taxes that are eliminated in consolidation. The majority of the remaining $14 million in assets represents cash equivalents.

(e) Total Assets of $1.2 billion for the Investments-Gas Operations segment include $429 million in affiliated accounts receivable related to the corporate borrowing program and risk management contracts that are eliminated in consolidation. The majority of the remaining $770 million in assets represents third party risk management contracts, margin deposits, and accounts receivable.

(f) Total Assets of $632 million for the Investments-UK Operations segment include $613 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 and value-added tax receivables.

13. FINANCING ACTIVITIES

Long-term Debt

Our outstanding long-term debt is as follows:

Type of Debt	**September 30, 2006**	**December 31, 2005**
	(in millions)	
Pollution Control Bonds	$ 2,051	$ 1,935
Senior Unsecured Notes	8,827	8,226
First Mortgage Bonds	96	196
Defeased First Mortgage Bonds (a)	26	26
Notes Payable	872	904
Securitization Bonds	596	648
Notes Payable To Trust	113	113
Other Long-Term Debt (b)	247	236
Unamortized Discount (net)	(65)	(58)
Total Long-term Debt Outstanding	12,763	12,226
Less Portion Due Within One Year	1,789	1,153
Long-term Portion	$ 10,974	$ 11,073

(a) In May 2004, we deposited cash and treasury securities with a trustee to defease all of TCC's outstanding First Mortgage Bonds. The defeased TCC First Mortgage Bonds had a balance of $18 million at both September 30, 2006 and December 31, 2005. Trust fund assets related to this obligation of $2 million are included in Other Temporary Cash Investments at both September 30, 2006 and December 31, 2005 and $21 million is included in Other Noncurrent Assets in the Condensed Consolidated Balance Sheets at both September 30, 2006 and December 31, 2005. In December 2005, we deposited cash and treasury securities with a trustee to defease the remaining TNC outstanding First Mortgage Bond. The defeased TNC First Mortgage Bond had a balance of $8 million at both September 30, 2006 and December 31, 2005. Trust fund assets related to this obligation of $9 million and $1 million at September 30, 2006 and December 31, 2005, respectively, are included in Other Temporary Cash Investments and $0 and $8 million are included in Other Noncurrent Assets in the Condensed Consolidated Balance Sheets at September 30, 2006 and December 31, 2005, respectively. Trust fund assets are restricted for exclusive use in funding the interest and principal due on the First Mortgage Bonds.

(b) Pursuant to the Nuclear Waste Policy Act of 1982, I&M (a nuclear licensee) has an obligation with the United States Department of Energy for spent nuclear fuel disposal. The obligation includes a one-time fee for nuclear fuel consumed prior to April 7, 1983. Trust fund assets of $270 million and $264 million related to this obligation are included in Spent Nuclear Fuel and Decommissioning Trusts in the Condensed Consolidated Balance Sheets at September 30, 2006 and December 31, 2005, respectively.

Long-term debt issued, retired and principal payments made during the first nine months of 2006 are shown in the tables below.

Company	**Type of Debt**	**Principal Amount (in millions)**	**Interest Rate (%)**	**Due Date**
Issuances:				
APCo	Pollution Control Bonds	$ 50	Variable	2036
APCo	Senior Unsecured Notes	250	5.55	2011

APCo	Senior Unsecured Notes		250	6.375	2036
I&M	Pollution Control Bonds		50	Variable	2025
OPCo	Pollution Control Bonds		65	Variable	2036
OPCo	Senior Unsecured Notes		350	6.00	2016
PSO	Senior Unsecured Notes		150	6.15	2016
SWEPCo	Pollution Control Bonds		82	Variable	2018
Total Issuances		$	1,247(a)		

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

(a) Amount indicated on statement of cash flows of $1,229 million is net of issuance costs and unamortized premium or discount.

Company	Type of Debt		Principal Amount Paid (in millions)	Interest Rate (%)	Due Date
Retirements and Principal Payments:					
AEP	Senior Unsecured Notes	$	396	6.125	2006
APCo	First Mortgage Bonds		100	6.80	2006
I&M	Pollution Control Bonds		50	6.55	2025
OPCo	Notes Payable		4	6.81	2008
OPCo	Notes Payable		7	6.27	2009
SWEPCo	Notes Payable		5	4.47	2011
SWEPCo	Notes Payable		2	Variable	2008
SWEPCo	Pollution Control Bonds		82	6.10	2018
TCC	Securitization Bonds		52	5.01	2010
Non-Registrant:					
AEP subsidiaries	Notes Payable		9	Variable	2017
CSW Energy, Inc.	Notes Payable		4	5.88	2011
Total Retirements and Principal Payments		$	711		

In October 2006, TCC issued $1.74 billion in securitization bonds as follows:

	Principal Amount (in millions)	Interest Rate (%)	Scheduled Final Payment Date
$	217	4.98	2010
	341	4.98	2013
	250	5.09	2015
	437	5.17	2018
	495	5.3063	2020

The proceeds will be used to retire TCC debt and equity, which are no longer needed to support stranded costs.

In October 2006, I&M had a required remarketing of $65 million of 2.625% pollution control bonds, which were converted from a three-year fixed rate mode to an auction rate mode.

In November 2006, APCo had a required remarketing of $30 million of 2.80% pollution control bonds, which were converted from a three-year fixed rate mode to an auction rate mode.

In November 2006, APCo issued $17.5 million of variable rate pollution control bonds and retired $17.5 million, 2.70% pollution control bonds due in 2007.

In November 2006, $100.6 million of pollution control bonds were put back to TCC on the put date of November 1, 2006. TCC intends to hold these bonds for reissuance at a later date.

Credit Facilities

In April 2006, we amended the terms and increased the size of our credit facilities from $2.7 billion to $3 billion. The amended facilities are structured as two $1.5 billion credit facilities, with an option in each to issue up to $200 million as letters of credit, expiring separately in March 2010 and April 2011. We also terminated an existing $200 million letter of credit facility.

AEP GENERATING COMPANY

AEP GENERATING COMPANY
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

As co-owner of the Rockport Plant, we engage in the generation and wholesale sale of electric power to two affiliates, I&M and KPCo, under long-term agreements. I&M is the operator and co-owner of the Rockport Plant.

We derive operating revenues from the sale 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. Under the terms of the unit power agreements, we accumulate all expenses monthly and prepare bills for our affiliates. In the month the expenses are incurred, we recognize the billing revenues and establish a receivable from the affiliated companies. We divide costs of operating the plant between the co-owners.

Results of Operations

Net Income was unchanged for the third quarter of 2006 compared with the third quarter of 2005. Net Income increased $0.6 million for the nine months ended September 30, 2006 compared with the nine months ended September 30, 2005. The fluctuation in Net Income is a result of terms in the unit power agreements which allow for a return on total capital of the Rockport Plant which is calculated and adjusted monthly.

Third Quarter of 2006 Compared to Third Quarter of 2005

Reconciliation of Third Quarter of 2005 to Third Quarter of 2006 Net Income
(in millions)

Third Quarter of 2005		$	2.2
Change in Gross Margin:			
Wholesale Sales			0.2
Changes in Operating Expenses and Other:			
Other Operation and Maintenance	(0.7)		
Taxes Other Than Income Taxes	0.7		
Interest Expense	(0.1)		
Total Change in Operating Expenses and Other			(0.1)
Income Tax Expense			(0.1)
Third Quarter of 2006		$	2.2

Gross Margin, defined as Operating Revenues less Fuel for Electric Generation, increased $0.2 million primarily due to recovery of higher expenses.

Other Operation and Maintenance expenses increased primarily due to increased costs at the Rockport Plant for steam plant operation and maintenance of structures.

Taxes Other Than Income Taxes decreased primarily due to lower real and personal property taxes as the prior year accrual was adjusted to the actual amount paid.

Nine Months Ended September 30, 2006 Compared to Nine Months Ended September 30, 2005

Reconciliation of Nine Months Ended September 30, 2005 to
Nine Months Ended September 30, 2006 Net Income
(in millions)

Nine Months Ended September 30, 2005		$ 6.8
Changes in Gross Margin:		
Wholesale Sales		3.2
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(2.0)	
Taxes Other Than Income Taxes	0.7	
Interest Expense	(0.3)	
Total Change in Operating Expenses and Other		(1.6)
Income Tax Expense		(1.0)
Nine Months Ended September 30, 2006		$ 7.4

Gross Margin, defined as Operating Revenues less Fuel for Electric Generation, increased $3.2 million primarily due to recovery of higher expenses and higher returns earned on plant and capital investment.

Other Operation and Maintenance expenses increased $2.0 million primarily due to increased maintenance cost at the Rockport Plant during a planned outage in 2006 and credits allocated to us in February 2005 from the cancellation and settlement of corporate owned life insurance policies.

Taxes Other Than Income Taxes decreased $0.7 million primarily due to lower real and personal property taxes as the prior year accrual was adjusted to the actual amount paid.

Income Taxes

Income Tax Expense increased $1.0 million primarily due to an increase in pretax book income and changes in certain book/tax differences accounted for on a flow-through basis.

Off-Balance Sheet Arrangements

In prior years, we entered into an off-balance sheet arrangement for the lease of Rockport Plant Unit 2. Our current guidelines restrict the use of off-balance sheet financing entities or structures to allow only 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 2005 Annual Report.

Summary Obligation Information

A summary of our contractual obligations is included in our 2005 Annual Report and has not changed significantly from year-end.

Significant Factors

In July 2006, we remarketed $45 million of pollution control bonds at a rate of 4.15% compared to a previous rate of 4.05% until July 14, 2011, the next remarketing date.

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

Critical Accounting Estimates

See the “Critical Accounting Estimates” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” in the 2005 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, 2006 and 2005
(Unaudited)
(in thousands)

	Three Months Ended 2006	Three Months Ended 2005	Nine Months Ended 2006	Nine Months Ended 2005
OPERATING REVENUES	$ 74,756	$ 69,640	$ 230,102	$ 201,268
EXPENSES				
Fuel for Electric Generation	42,354	37,403	131,402	105,771
Rent - Rockport Plant Unit 2	17,070	17,070	51,212	51,212
Other Operation	3,381	2,803	9,598	8,376
Maintenance	2,522	2,421	7,238	6,411
Depreciation and Amortization	5,951	5,956	17,858	17,901
Taxes Other Than Income Taxes	368	1,074	2,466	3,149
TOTAL	71,646	66,727	219,774	192,820
OPERATING INCOME	3,110	2,913	10,328	8,448
Other Income (Expense):				
Interest Income	-	-	-	24
Allowance for Equity Funds Used During Construction	-	-	24	60
Interest Expense	(774)	(652)	(2,137)	(1,848)
INCOME BEFORE INCOME TAXES	2,336	2,261	8,215	6,684
Income Tax Expense (Credit)	117	22	848	(144)
NET INCOME	$ 2,219	$ 2,239	$ 7,367	$ 6,828

CONDENSED STATEMENTS OF RETAINED EARNINGS
For the Three and Nine Months Ended September 30, 2006 and 2005
(Unaudited)
(in thousands)

	Three Months Ended 2006	Three Months Ended 2005	Nine Months Ended 2006	Nine Months Ended 2005
BALANCE AT BEGINNING OF PERIOD	$ 27,176	$ 26,947	$ 26,038	$ 24,237
Net Income	2,219	2,239	7,367	6,828
Cash Dividends Declared	-	3,015	4,010	4,894
BALANCE AT END OF PERIOD	$ 29,395	$ 26,171	$ 29,395	$ 26,171

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

AEP GENERATING COMPANY
CONDENSED BALANCE SHEETS
ASSETS
September 30, 2006 and December 31, 2005
(Unaudited)
(in thousands)

		2006		2005
CURRENT ASSETS				
Accounts Receivable - Affiliated Companies	$	24,356	$	29,671
Fuel		24,139		14,897
Materials and Supplies		7,913		7,017
Accrued Tax Benefits		2,009		2,074
Prepayments and Other		105		9
TOTAL		58,522		53,668
PROPERTY, PLANT AND EQUIPMENT				
Electric - Production		686,025		684,721
Other		2,385		2,369
Construction Work in Progress		11,391		12,252
Total		699,801		699,342
Accumulated Depreciation and Amortization		393,529		382,925
TOTAL - NET		306,272		316,417
Noncurrent Assets		7,738		6,618
TOTAL ASSETS	$	372,532	$	376,703

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

AEP GENERATING COMPANY
CONDENSED BALANCE SHEETS
LIABILITIES AND SHAREHOLDER'S EQUITY
September 30, 2006 and December 31, 2005
(Unaudited)

		2006		2005
CURRENT LIABILITIES		(in thousands)		
Advances from Affiliates	$	14,938	$	35,131
Accounts Payable:				
General		1,311		926
Affiliated Companies		21,018		22,161
Long-term Debt Due Within One Year		-		44,828
Accrued Taxes		5,880		3,055
Accrued Rent - Rockport Plant Unit 2		23,427		4,963
Other		805		1,228
TOTAL		67,379		112,292
NONCURRENT LIABILITIES				
Long-term Debt		44,835		-
Deferred Income Taxes		20,852		23,617
Asset Retirement Obligations		1,399		1,370
Regulatory Liabilities and Deferred Investment Tax Credits		82,331		82,689
Deferred Gain on Sale and Leaseback - Rockport Plant Unit 2		90,155		94,333
Obligations Under Capital Leases		11,752		11,930
TOTAL		251,324		213,939
TOTAL LIABILITIES		318,703		326,231
Commitments and Contingencies (Note 5)				
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		29,395		26,038
TOTAL		53,829		50,472
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$	372,532	$	376,703

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

AEP GENERATING COMPANY
CONDENSED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2006 and 2005
(in thousands)
(Unaudited)

	2006	2005
OPERATING ACTIVITIES		
Net Income	$ 7,367	$ 6,828
Adjustments for Noncash Items:		
Depreciation and Amortization	17,858	17,901
Deferred Income Taxes	(3,468)	(3,539)
Deferred Investment Tax Credits	(2,482)	(2,501)
Amortization of Deferred Gain on Sale and Leaseback - Rockport Plant Unit 2	(4,178)	(4,178)
Deferred Property Taxes	(893)	(1,010)
Changes in Other Noncurrent Assets	(2,885)	(1,736)
Changes in Other Noncurrent Liabilities	2,776	2,201
Changes in Components of Working Capital:		
Accounts Receivable	5,315	(2,469)
Fuel, Materials and Supplies	(10,138)	4,278
Accounts Payable	(758)	(1,188)
Accrued Taxes, Net	2,890	(2,982)
Rent Accrued - Rockport Plant Unit 2	18,464	18,464
Other Current Assets	(96)	(17)
Other Current Liabilities	(423)	(363)
Net Cash Flows From Operating Activities	29,349	29,689
INVESTING ACTIVITIES		
Construction Expenditures	(4,978)	(9,041)
FINANCING ACTIVITIES		
Change in Advances from Affiliates, Net	(20,193)	(15,601)
Principal Payments for Capital Lease Obligations	(168)	(153)
Dividends Paid	(4,010)	(4,894)
Net Cash Flows Used For Financing Activities	(24,371)	(20,648)
Net Change in Cash and Cash Equivalents	-	-
Cash and Cash Equivalents at Beginning of Period	-	-
Cash and Cash Equivalents at End of Period	$ -	$ -
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 2,413	$ 2,104
Net Cash Paid for Income Taxes	6,037	11,025
Noncash Acquisitions Under Capital Leases	78	31

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

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

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARIES

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

Allocation Agreement between AEP East companies and AEP West companies

Under the Texas Restructuring Legislation, we are completing the final stage of exiting the generation business and have ceased serving retail load. Based on the corporate separation and generation divestiture activities underway, the nature of our business is no longer compatible with our participation in the CSW Operating Agreement and the SIA since these agreements involve the coordinated planning and operation of power supply facilities. Accordingly, on behalf of the AEP East companies and the AEP West companies, AEPSC filed with the FERC to remove us from those agreements. The FERC approved the filing in March 2006. The SIA includes a methodology for sharing trading and marketing margins among the AEP East companies and the AEP West companies. Our sharing of margins ceased effective May 1, 2006, which affects our future results of operations and cash flows. We will continue to have margin and collateral deposits, risk management assets and liabilities and trading gains or losses to the extent that we have contracts dedicated specifically to us. As of September 30, 2006, we have no dedicated contracts.

Results of Operations

Third Quarter of 2006 Compared to Third Quarter of 2005

Reconciliation of Third Quarter of 2005 to Third Quarter of 2006 Net Income
(in millions)

Third Quarter of 2005		$	40
Changes in Gross Margin:			
Texas Supply	(4)		
Texas Wires	(1)		
Off-system Sales	(18)		
Transmission Revenues	(3)		
Other	(3)		
Total Change in Gross Margin			(29)
Changes in Operating Expenses and Other:			
Other Operation and Maintenance	1		
Carrying Costs Income	10		
Other Income	(7)		
Interest Expense	(11)		
Total Change in Operating Expenses and Other			(7)
Income Tax Expense			13
Third Quarter of 2006		$	17

Net Income decreased $23 million to $17 million in 2006. The key drivers of the decrease were a $29 million decrease in Gross Margin and a $7 million increase in Operating Expenses and Other, partially offset by a reduction in Income Tax Expense of $13 million. We substantially exited the generation market with the sale of STP in May 2005.

The major components of our change in Gross Margin, defined as revenues less the related direct cost of fuel, consumption of chemicals and emissions allowances, and purchased power, were as follows:

- Texas Supply margins decreased $4 million primarily due to lower nonaffiliated sales of $3 million.
- Margins from Off-system Sales decreased $18 million due to an $11 million decrease in margin sharing under the SIA (no current margin sharing under the CSW Operating Agreement and the SIA) and a $7 million decrease in margins from optimization activities. See the “Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement” section of Note 3.
- Transmission Revenues decreased $3 million primarily due to lower ERCOT transmission rates and reduced affiliated transmission fees resulting from the elimination of the affiliated OATT in 2005.
- Other revenues decreased $3 million primarily due to lower securitization revenues of $3 million. Securitization revenues represent amounts collected to recover securitization bond principal and interest payments related to our securitized transition assets and are fully offset by amortization and interest expenses.

Operating Expenses and Other changed between years as follows:

- Carrying Costs Income increased $10 million primarily due to a negative adjustment of $8 million made in the third quarter of 2005 related to our True-up Proceeding orders received from the PUCT.
- Other Income decreased $7 million primarily due to interest income recorded in the prior year related to the 2005 Texas Court of Appeals order (see “Texas Restructuring - Excess Earnings” section of Note 4).
- Interest Expense increased $11 million primarily due to a $9 million increase in accrued interest related to the Texas competition transition charge liability (See “Texas Restructuring - CTC Proceeding for Other True-up Items” section of Note 4).

Income Taxes

The decrease in Income Tax Expense of $13 million is primarily due to a decrease in pretax book income.

Nine Months Ended September 30, 2006 Compared to Nine Months Ended September 30, 2005

Reconciliation of Nine Months Ended September 30, 2005 to
Nine Months Ended September 30, 2006 Net Income
(in millions)

Nine Months Ended September 30, 2005		$	70
Changes in Gross Margin:			
Texas Supply	(78)		
Texas Wires	14		
Off-system Sales	(21)		
Transmission Revenues	(12)		
Other	(9)		
Total Change in Gross Margin			(106)
Changes in Operating Expenses and Other:			

Other Operation and Maintenance	50		
Depreciation and Amortization	(6)		
Taxes Other Than Income Taxes	6		
Carrying Costs Income	35		
Other Income	(13)		
Interest Expense	(8)		
Total Change in Operating Expenses and Other			64
Income Tax Expense			10
Nine Months Ended September 30, 2006		$	38

Net Income decreased $32 million to $38 million in 2006. The key driver of the decrease was a $106 million decrease in Gross Margin, partially offset by a reduction in Other Operation and Maintenance expenses of $50 million and increased Carrying Costs Income of $35 million. We substantially exited the generation market with the sale of STP in May 2005.

The major components of our change in Gross Margin, defined as revenues less the related direct cost of fuel, consumption of chemicals and emissions allowances, and purchased power, were as follows:

· Texas Supply margins decreased $78 million primarily due to the sale of STP, which resulted in lower nonaffiliated sales of $101 million and a $6 million provision for refund primarily due to the fuel reconciliation adjustment in 2005. These decreases were partially offset by lower fuel and purchased power expenses of $30 million.
· Texas Wires revenues increased $14 million primarily due to favorable prices and a five percent increase in degree days.
· Margins from Off-system Sales decreased $21 million due to a $15 million decrease in margin sharing under the SIA and a $6 million decrease in margins from optimization activities. See the “Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement” section of Note 3.
· Transmission Revenues decreased $12 million primarily due to lower ERCOT transmission rates and reduced affiliated transmission fees resulting from the elimination of the affiliated OATT in 2005.
· Other revenues decreased $9 million primarily due to lower third party construction project revenues of $4 million related to work performed for the Lower Colorado River Authority and reduced securitization revenues of $6 million. Securitization revenues represent amounts collected to recover securitization bond principal and interest payments related to our securitized transition assets and are fully offset by amortization and interest expenses.

Operating Expenses and Other changed between years as follows:

· Other Operation and Maintenance expenses decreased $50 million primarily due to a $12 million decrease in plant operations, a $14 million decrease in plant maintenance, a $6 million decrease in administrative and general expenses and the absence of $7 million in accretion expense all related to the sale of STP. An additional $4 million decrease resulted from lower expenses related to construction activities performed for third parties, primarily the Lower Colorado River Authority.
· Depreciation and Amortization expense increased $6 million primarily related to the refund and amortization of excess earnings credits in 2005 partially offset by the recovery and amortization of securitized assets.
·

Taxes Other Than Income Taxes decreased $6 million primarily due to lower property-related taxes as a result of the sale of STP in 2005 and the favorable settlement of a state use tax audit in 2006.

- Carrying Costs Income increased $35 million primarily due to negative adjustments of $29 million and $8 million made in the first and third quarters of 2005, respectively, related to our True-up Proceeding orders received from the PUCT.
- Other Income decreased $13 million primarily due to interest income recorded in the prior year related to the 2005 Texas Court of Appeals order (See "Texas Restructuring - Excess Earnings" section of Note 4).
- Interest Expense increased $8 million primarily due to a $12 million increase in accrued interest related to the Texas CTC liability (see "Texas Restructuring - CTC Proceeding for Other True-up Items" section of Note 4) partially offset by a $2 million decrease in interest expense associated with securitization revenues.

Income Taxes

The decrease in Income Tax Expense of $10 million is primarily due to a decrease in pretax book income, offset in part by tax reserve adjustments, a decrease in the amortization of investment tax credits due to the sale in May 2005 of STP and a decrease in consolidated tax savings from AEP.

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, 2006 and 2005 were as follows:

		2006		**2005**
		(in thousands)		
Cash and Cash Equivalents at Beginning of Period	$	-	$	26
Net Cash Flows From (Used For):				
Operating Activities		137,471		(95,431)
Investing Activities		(197,269)		293,461
Financing Activities		59,803		(198,053)
Net Increase (Decrease) in Cash and Cash Equivalents		5		(23)
Cash and Cash Equivalents at End of Period	$	5	$	3

Operating Activities

Net Cash Flows From Operating Activities were $137 million during the first nine months of 2006. We produced Net Income of $38 million during the period and incurred noncash items of $111 million for Depreciation and Amortization and $(65) million for Carrying Costs on Stranded Cost Recovery. 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 working capital relates to a number of items; the most significant are decreases in Accounts Receivable, Net partially offset by a decrease in Accounts Payable. Accounts Receivable, Net decreased $159 million primarily due to cash received for the retail clawback of $61 million and 2005 storm restoration performed for nonaffiliated companies of $12 million. In addition, our removal from the SIA and CSW Operating Agreement effective May 1, 2006 resulted in fewer energy-related receivables. Accounts Payable decreased $108 million primarily due to lower energy-related transactions resulting from our removal from the SIA and CSW Operating Agreement.

Net Cash Flows Used For Operating Activities were $95 million during 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 activity in these asset and liability accounts relate to a number of items; the most significant is a decrease in Accrued Taxes, Net. Accrued Taxes, Net decreased $111 million primarily as a result of taxes remitted to the government related to prior year and current year tax accruals.

Investing Activities

Net Cash Flows Used For Investing Activities in 2006 were $197 million primarily due to $203 million of Construction Expenditures focused mainly on improved service reliability projects for transmission and distribution systems. For the remainder of 2006, we expect $83 million in Construction Expenditures.

Net Cash Flows From Investing Activities in 2005 were $293 million primarily due to $314 million of net proceeds from the sale of the STP nuclear plant and a reduction in Other Cash Deposits, Net of $93 million primarily for the retirement of defeased first mortgage bonds of $66 million. These cash inflows were partially offset by cash used for construction expenditures of $109 million related to projects for transmission and distribution service reliability.

Financing Activities

Net Cash Flows From Financing Activities in 2006 were $60 million primarily due to the issuance of $195 million of affiliated notes with AEP. This increase in long-term debt was partially offset by a decrease in Advances from Affiliates, Net of $82 million and the retirement of $52 million of securitization bonds.

Net Cash Flows Used for Financing Activities in 2005 were $198 million 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.

Financing Activity

Long-term debt issuances and retirements during the first nine months of 2006 were:

<u>Issuances</u>

Type of Debt	Principal Amount	Interest Rate	Due Date

		(in thousands)	(%)	
Notes Payable - Affiliated	$	125,000	5.14	2007
Notes Payable - Affiliated		70,000	5.86	2007

<u>Retirements</u>

Type of Debt		Principal Amount (in thousands)	Interest Rate (%)	Due Date
Securitization Bonds	$	52,265	5.01	2010

In October 2006 TCC issued $1.74 billion in securitization bonds, as follows:

	Principal Amount (in thousands)	Interest Rate (%)	Scheduled Final Payment Date
$	217,000	4.98	2010
	341,000	4.98	2013
	250,000	5.09	2015
	437,000	5.17	2018
	494,700	5.3063	2020

The proceeds will generally be used to retire TCC debt and equity, which are no longer needed to support stranded costs.

In October 2006, we retired $345 million in intercompany notes payable as follows:

	Principal Amount (in thousands)	Interest Rate (%)	Due Date
$	150,000	4.58	2007
	125,000	5.14	2007
	70,000	5.86	2007

In November 2006, $100.6 million of pollution control bonds were put back to TCC on the put date of November 1, 2006. TCC intends to hold these bonds for reissuance at a later date.

In October 2006, we also paid a special dividend of $585 million to AEP.

Liquidity

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

We will use proceeds received from the securitization to pay down a portion of our equity and debt and to pay any necessary accelerated refunds related to the CTC (discussed below under Texas Restructuring).

Summary Obligation Information

A summary of our contractual obligations is included in our 2005 Annual Report and has not changed significantly from year-end other than the debt issuances and retirements discussed above.

Significant Factors

Texas Restructuring

In June 2006, we filed to implement a CTC refund of $357 million for our other true-up items over eight years. The differences between the components of our Recorded Net Regulatory Liabilities - Other True-up Items as of September 30, 2006 (including interest) and our Net CTC Refund Proposed are detailed below**:**

		(in millions)
Wholesale Capacity Auction True-up	$	61
Carrying Costs on Wholesale Capacity Auction True-up		31
Retail Clawback including Carrying Costs		(65)
Deferred Over-recovered Fuel Balance		(184)
Retrospective ADFIT Benefit		(77)
Other		(4)
Recorded Net Regulatory Liabilities - Other True-up Items		(238)
Unrecorded Prospective ADFIT Benefit		(240)
Gross CTC Refund Proposed		(478)
FERC Jurisdictional Fuel Refund Deferral		16
ADITC and EDFIT Benefit Refund Deferral		98
Net CTC Refund Proposed, After Deferrals		(364)
True-up Proceeding Expense Surcharge		7
Net CTC Refund Proposed, After Deferrals and Expenses	$	(357)

In September 2006, the PUCT approved an interim CTC that was implemented on October 12, 2006, the same day that we began billing customers for the securitization bonds. The interim CTC will refund the entire retail clawback of $65 million (including carrying costs) to residential customers by the end of 2006. The CTC refund to the other customer classes during the interim period will be as proposed by us, with the exception of the large industrials, who will not receive any fuel refunds during the interim period.

At an October 2006 open meeting, the PUCT announced oral decisions regarding the CTC refund. A final written order is expected in late November or early December of this year. In its decision, the PUCT confirmed that TCC can use securitization bond proceeds to make the CTC refund. The PUCT's decision was to continue the interim CTC through December 2006 to complete the refund of the retail clawback over three months. Beginning in January 2007, the Deferred Over-recovered Fuel Balance will be refunded over six months with the large industrial customers receiving their entire refund in January 2007. Starting in July 2007, the remaining CTC items will be refunded over one year, except that the PUCT agreed with our request to defer the refund of the ADITC and EDFIT Benefit Refund

Deferral and the FERC Jurisdictional Fuel Refund Deferral (see table above). The PUCT will decide those issues and related amounts in another proceeding.

Municipal customers and other intervenors appealed the PUCT orders seeking to further reduce our true-up recoveries. If we determine, as a result of future PUCT orders or appeal court rulings, that it is probable we cannot recover a portion of our recorded net true-up regulatory asset and we are able to estimate the amount of a resultant impairment, we would record a provision for such amount which would have an adverse effect on future results of operations, cash flows and possibly financial condition. We appealed the PUCT orders seeking relief in both state and federal court where we believe the PUCT's rulings are contrary to the Texas Restructuring Legislation, PUCT rulemakings and federal law. The significant items appealed by TCC are:

- the PUCT ruled that TCC did not comply with the statute and PUCT rules regarding the auction of 15% of its Texas jurisdictional installed capacity,
- that TCC acted in a manner that was commercially unreasonable because it failed to determine a minimum price at which it would reject bids for the sale of its nuclear generating plant and it bundled gas units with the sale of its coal unit,
- and two federal matters regarding the allocation of off-system sales related to fuel recoveries and the potential tax normalization violation.

These appeals could take years to resolve and could result in material effects on future results of operations. If the PUCT rejects our deferral proposal and a normalization violation occurs, future results of operations and cash flows could be adversely affected by the recapture of $104 million of our ADITC and the loss of future accelerated tax depreciation election. The estimated future impact on earnings of the Texas Restructuring as of September 30, 2006, exclusive of a possible normalization violation and any effects of appeal litigation, over the 14-year securitization net recovery period assuming the PUCT approves our CTC filing, including the interim refund, is detailed below:

		(in millions)
ADITC and EDFIT Benefits Reducing Securitization	$	98
ADFIT Benefit Applied to Reduce 2002 Securitization of Regulatory Assets		(60)
Securitization Settlement		(77)
Unrecorded Prospective ADFIT Benefit Increasing the CTC Refund		(240)
Unrecorded Equity Carrying Costs Recognized as Collected		224
Future Interest Payable on Proposed CTC Refund		(19)
Deferred Fuel - Federal Jurisdictional Issue		16
Net Adverse Earnings Impact Over 14 Years	$	(58)

If the PUCT changes its oral decision regarding the proposed CTC deferral and the two contingent federal matters are refunded to customers, the future adverse impact on results of operations over the next 14 years will increase to $181 million. This potential adverse impact on results of operations over the next 14 years would be more than offset by the annual cost of money benefit from the $2.2 billion in net proceeds that resulted from the sale of bonds in connection with the initial regulatory asset securitization in 2002 of $797 million and from the $1.74 billion sale of securitization bonds in October 2006 less the proposed $357 million CTC refund over the next eight years.

Litigation and Regulatory Activity

In the ordinary course of business, we are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot state what the eventual outcome of these proceedings will be, or what the timing of the amount of any loss, fine or penalty may be. Management does, however, assess the probability of loss for such contingencies and accrues a liability for cases which have a probable likelihood of loss and the loss amount can be estimated. For details on our pending litigation and regulatory proceedings, see Note 4 - Rate Matters, Note 6 - Customer Choice and Industry Restructuring and Note 7 - Commitments and Contingencies in our 2005 Annual Report. Also, see Note 3 - Rate Matters, Note 4 - Customer Choice and Industry Restructuring and Note 5 - Commitments and Contingencies in the “Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries” section. Adverse results in these proceedings have the potential to materially affect our results of operations, financial condition and cash flows.

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

Critical Accounting Estimates

See the “Critical Accounting Estimates” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” in the 2005 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, 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

Our MTM Risk Management Contract Net Assets are zero as of September 30, 2006. For further explanation, see "Allocation Agreement between AEP East companies and AEP West companies" section of this Management's Financial Discussion and Analysis.

The following table summarizes the reasons for changes in our total MTM value as compared to December 31, 2005.

MTM Risk Management Contract Net Assets
Nine Months Ended September 30, 2006
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2005	$	5,426
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period		(1,175)
Fair Value of New Contracts at Inception When Entered During the Period (a)		-
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period		-
Changes in Fair Value Due to Valuation Methodology Changes on Forward Contracts		-
Changes in Fair Value Due to Market Fluctuations During the Period (b)		(3,868)
Changes Due to SIA and CSW Operating Agreement (c)		(383)
Changes in Fair Value Allocated to Regulated Jurisdictions (d)		-
Total MTM Risk Management Contract Net Assets		-
Net Cash Flow Hedge Contracts		-
Total MTM Risk Management Contract Net Assets at September 30, 2006	$	-

(a) 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.
(b) Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
(c) See "Allocation Agreement between AEP East companies and AEP West companies" section of this Management's Financial Discussion and Analysis.
(d) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Condensed Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.

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

Our MTM Risk Management Contracts Net Assets are zero as of September 30, 2006. Therefore, there is no maturity and source of fair value to report.

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

As a result of changes made to the Allocation Agreement between AEP East companies and AEP West companies in the second quarter of 2006, we are no longer exposed to market fluctuations in energy commodity prices. Therefore, we have no contracts designated as cash flow hedges on our September 30, 2006 Condensed Consolidated Balance Sheet.

The following table provides the detail on designated, effective cash flow hedges included in AOCI on our Condensed Consolidated Balance Sheets and the reasons for the changes from December 31, 2005 to September 30, 2006. Only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts that are not designated as effective cash flow hedges are marked-to-market and included in the previous risk management tables. All amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Nine Months Ended September 30, 2006
(in thousands)

	Power
Beginning Balance in AOCI December 31, 2005	$ (224)
Changes in Fair Value	-
Impact Due to Changes in SIA (a)	218
Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled	6
Ending Balance in AOCI September 30, 2006	$ -

(a) See “Allocation Agreement between AEP East companies and AEP West companies” section of this Management’s Financial Discussion and Analysis.

Credit Risk

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

VaR Associated with Risk Management Contracts

We use a risk measurement model, which calculates Value at Risk (VaR) to measure our commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, at September 30, 2006, a near term typical change in commodity prices is not expected to have a material effect on our results of operations, cash flows or financial condition.

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

Nine Months Ended September 30, 2006 (in thousands)				Twelve Months Ended December 31, 2005 (in thousands)			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$-	$11	$2	$-	$111	$184	$88	$32

VaR Associated with Debt Outstanding

We also utilize a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. 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 $70 million and $93 million at September 30, 2006 and December 31, 2005, 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 operations or consolidated financial position.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2006 and 2005
(in thousands)
(Unaudited)

	Three Months Ended		Nine Months Ended	
	2006	**2005**	**2006**	**2005**
REVENUES				
Electric Generation, Transmission and Distribution	$ 162,902	$ 192,932	$ 435,801	$ 559,822
Sales to AEP Affiliates	1,559	2,528	4,703	12,794
Other - Nonaffiliated	9,462	7,905	30,196	34,432
TOTAL	173,923	203,365	470,700	607,048
EXPENSES				
Fuel and Other Consumables for Electric Generation	2,006	1,915	4,728	12,047
Purchased Electricity for Resale	725	1,691	3,557	27,057
Other Operation	61,057	64,408	183,241	221,741
Maintenance	10,679	8,782	27,255	38,254
Depreciation and Amortization	40,298	40,342	110,848	105,062
Taxes Other Than Income Taxes	23,387	22,828	60,421	66,282
TOTAL	138,152	139,966	390,050	470,443
OPERATING INCOME	35,771	63,399	80,650	136,605
Other Income (Expense):				
Interest Income	560	8,295	1,592	15,722
Carrying Costs Income	25,443	15,349	65,279	30,146
Allowance for Equity Funds Used During Construction	667	(59)	1,671	641
Interest Expense	(36,746)	(25,374)	(93,401)	(85,095)
INCOME BEFORE INCOME TAXES	25,695	61,610	55,791	98,019
Income Tax Expense	8,460	21,134	17,808	28,038
NET INCOME	17,235	40,476	37,983	69,981
Preferred Stock Dividend Requirements	60	60	181	181
EARNINGS APPLICABLE TO COMMON STOCK	$ 17,175	$ 40,416	$ 37,802	$ 69,800

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Nine Months Ended September 30, 2006 and 2005
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
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
DECEMBER 31, 2005	$ 55,292	$ 132,606	$ 760,884	$ (1,152)	$ 947,630
Preferred Stock Dividends			(181)		(181)
TOTAL					947,449
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $121				224	224
NET INCOME			37,983		37,983
TOTAL COMPREHENSIVE INCOME					38,207
SEPTEMBER 30, 2006	$ 55,292	$ 132,606	$ 798,686	$ (928)	$ 985,656

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2006 and December 31, 2005
(in thousands)
(Unaudited)

	2006	2005
CURRENT ASSETS		
Cash and Cash Equivalents	$ 5	$ -
Other Cash Deposits	41,728	66,153
Advances to Affiliates	25,304	-
Accounts Receivable:		
Customers	65,875	209,957
Affiliated Companies	8,633	23,486
Accrued Unbilled Revenues	25,350	25,606
Allowance for Uncollectible Accounts	(217)	(143)
Total Accounts Receivable	99,641	258,906
Unbilled Construction Costs	6,352	19,440
Materials and Supplies	24,995	13,897
Risk Management Assets	-	14,311
Prepayments and Other	5,645	5,231
TOTAL	203,670	377,938
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Transmission	900,774	817,351
Distribution	1,559,593	1,476,683
Other	232,023	233,361
Construction Work in Progress	126,418	129,800
Total	2,818,808	2,657,195
Accumulated Depreciation and Amortization	637,517	636,078
TOTAL - NET	2,181,291	2,021,117
OTHER NONCURRENT ASSETS		
Regulatory Assets	1,710,352	1,688,787
Securitized Transition Assets	557,520	593,401
Long-term Risk Management Assets	-	11,609
Employee Benefits and Pension Assets	112,594	114,733
Deferred Charges and Other	57,276	53,011
TOTAL	2,437,742	2,461,541
Assets Held for Sale - Texas Generation Plants	45,863	44,316
TOTAL ASSETS	$ 4,868,566	$ 4,904,912

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
September 30, 2006 and December 31, 2005
(Unaudited)

	2006	2005
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ -	$ 82,080
Accounts Payable:		
General	20,889	82,666
Affiliated Companies	18,160	65,574
Long-term Debt Due Within One Year - Nonaffiliated	153,364	152,900
Long-term Debt Due Within One Year - Affiliated	345,000	-
Risk Management Liabilities	-	13,024
Accrued Taxes	74,887	54,566
Accrued Interest	16,011	32,497
Other	32,500	45,927
TOTAL	660,811	529,234
NONCURRENT LIABILITIES		
Long-term Debt - Nonaffiliated	1,498,031	1,550,596
Long-term Debt - Affiliated	-	150,000
Long-term Risk Management Liabilities	-	7,857
Deferred Income Taxes	1,014,840	1,048,372
Regulatory Liabilities and Deferred Investment Tax Credits	684,566	652,143
Deferred Credits and Other	18,723	13,140
TOTAL	3,216,160	3,422,108
TOTAL LIABILITIES	3,876,971	3,951,342
Cumulative Preferred Stock Not Subject to Mandatory Redemption	5,939	5,940
Commitments and Contingencies (Note 5)		
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	798,686	760,884
Accumulated Other Comprehensive Income (Loss)	(928)	(1,152)
TOTAL	985,656	947,630
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 4,868,566	$ 4,904,912

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2006 and 2005
(in thousands)
(Unaudited)

	2006	2005
OPERATING ACTIVITIES		
Net Income	$ 37,983	$ 69,981
Adjustments for Noncash Items:		
Depreciation and Amortization	110,848	105,062
Accretion of Asset Retirement Obligations	55	7,549
Deferred Income Taxes	5,770	(63,426)
Carrying Costs on Stranded Cost Recovery	(65,279)	(30,146)
Mark-to-Market of Risk Management Contracts	5,426	(1,139)
Over/Under Fuel Recovery	7,225	(2,000)
Deferred Property Taxes	(8,296)	(7,600)
Change in Other Noncurrent Assets	17,653	(9,777)
Change in Other Noncurrent Liabilities	(17,249)	(1,390)
Changes in Components of Working Capital:		
Accounts Receivable, Net	159,265	(22,504)
Fuel, Materials and Supplies	(11,508)	(1,763)
Accounts Payable	(107,505)	(10,533)
Customer Deposits	(6,461)	12,844
Accrued Taxes, Net	16,387	(110,975)
Accrued Interest	(16,486)	(24,495)
Other Current Assets	16,611	(13,709)
Other Current Liabilities	(6,968)	8,590
Net Cash Flows From (Used For) Operating Activities	137,471	(95,431)
INVESTING ACTIVITIES		
Construction Expenditures	(203,116)	(109,372)
Change in Other Cash Deposits, Net	25,068	93,427
Change in Advances to Affiliates, Net	(25,304)	-
Purchases of Investment Securities	-	(154,364)
Sales of Investment Securities	-	149,804
Proceeds from Sale of Assets	6,083	313,966
Net Cash Flows From (Used For) Investing Activities	(197,269)	293,461
FINANCING ACTIVITIES		
Issuance of Long-term Debt - Nonaffiliated	-	276,663
Issuance of Long-term Debt - Affiliated	195,000	150,000
Change in Advances from Affiliates, Net	(82,080)	11,814
Retirement of Long-term Debt	(52,265)	(486,007)
Retirement of Preferred Stock	(1)	-
Principal Payments for Capital Lease Obligations	(670)	(342)
Dividends Paid on Common Stock	-	(150,000)
Dividends Paid on Cumulative Preferred Stock	(181)	(181)
Net Cash Flows From (Used For) Financing Activities	59,803	(198,053)

Net Increase (Decrease) in Cash and Cash Equivalents		5		(23)
Cash and Cash Equivalents at Beginning of Period		-		26
Cash and Cash Equivalents at End of Period	$	5	$	3
SUPPLEMENTAL DISCLOSURE				
Cash Paid for Interest, Net of Capitalized Amounts	$	93,165	$	95,066
Net Cash Paid (Received) for Income Taxes		(2,764)		207,079
Noncash Acquisitions Under Capital Leases		3,282		277
Construction Expenditures Included in Accounts Payable at September 30,		9,351		8,797

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

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

AEP TEXAS NORTH COMPANY AND SUBSIDIARY

AEP TEXAS NORTH COMPANY AND SUBSIDIARY
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

Allocation Agreement between AEP East companies and AEP West companies

Under the Texas Restructuring Legislation, we are completing the final stage of exiting the generation business and have ceased serving retail load. Based on the corporate separation and generation divestiture activities underway, the nature of our business is no longer compatible with our participation in the CSW Operating Agreement and the SIA since these agreements involve the coordinated planning and operation of power supply facilities. Accordingly, on behalf of the AEP East companies and the AEP West companies, AEPSC filed with the FERC to remove us from those agreements. The FERC approved the filing in March 2006. The SIA includes a methodology for sharing trading and marketing margins among the AEP East companies and the AEP West companies. Our sharing of margins ceased effective May 1, 2006, which affects our future results of operations and cash flows. We will continue to have margin and collateral deposits, risk management assets and liabilities and trading gains or losses to the extent that we have contracts dedicated specifically to us.

AEP Texas North Generation Company, LLC

In the third quarter of 2006, we created a new wholly-owned subsidiary, AEP Texas North Generation Company, LLC (TNGC). Following the creation of this subsidiary, we transferred all of our mothballed generation assets and related liabilities to this new subsidiary, substantially completing the business separation requirement of the Texas Restructuring Legislation. Subsequently, TNGC became a participant in the Nonutility Money Pool. The creation of TNGC did not have a significant impact on our results of operations or financial condition.

Results of Operations

Third Quarter of 2006 Compared to Third Quarter of 2005

Reconciliation of Third Quarter of 2005 to Third Quarter of 2006 Net Income
(in millions)

Third Quarter of 2005		$	22
Changes in Gross Margin:			
Texas Supply	(12)		
Texas Wires	(1)		
Off-system Sales	(10)		
Transmission Revenues	1		
Total Change in Gross Margin			(22)
Changes in Operating Expenses and Other:			
Other Operation and Maintenance			1
Income Tax Expense			7
Third Quarter of 2006		$	8

Net Income decreased $14 million to $8 million in 2006 primarily due to a decrease in Gross Margin of $22 million, partially offset by a reduction in Income Tax Expense of $7 million.

The major components of our change in Gross Margin, defined as revenues less the related direct cost of fuel, consumption of chemicals and emissions allowances, and purchased power, were as follows:

- Texas Supply margins decreased $12 million primarily due to a $28 million decrease in dedicated energy and capacity sales, offset by $16 million of lower fuel and purchased power costs. This decrease in Texas Supply margins was affected by market conditions within ERCOT.
- Margins from Off-system Sales decreased $10 million due to a $5 million decrease in margin sharing under the SIA (no current margin sharing under the CSW Operating Agreement and the SIA) and a $5 million decrease in margins from optimization activities. See the "Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement" section of Note 3.

Income Taxes

The decrease in Income Tax Expense of $7 million is primarily due to a decrease in pretax book income.

Nine Months Ended September 30, 2006 Compared to Nine Months Ended September 30, 2005

Reconciliation of Nine Months Ended September 30, 2005 to Nine Months Ended September 30, 2006 Net Income (in millions)

Nine Months Ended September 30, 2005		$	42
Changes in Gross Margin:			
Texas Supply	(29)		
Texas Wires	(2)		
Off-system Sales	(11)		
Transmission Revenues	(5)		
Other	(39)		
Total Change in Gross Margin			(86)
Changes in Operating Expenses and Other:			
Other Operation and Maintenance	38		
Interest Expense	1		
Total Change in Operating Expenses and Other			39
Income Tax Expense			17
Nine Months Ended September 30, 2006		$	12

Net Income decreased $30 million to $12 million in 2006 primarily due to a decrease in Gross Margin of $86 million partially offset by a reduction in Other Operation and Maintenance expenses of $38 million and a reduction in Income Tax Expense of $17 million.

The major components of our change in Gross Margin, defined as revenues less the related direct cost of fuel, consumption of chemicals and emissions allowances, and purchased power, were as follows:

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Texas Supply margins decreased $29 million primarily due to a $58 million decrease in dedicated energy and capacity sales, offset by $28 million of lower fuel and purchased power costs. This decrease in Texas Supply margins was affected by market conditions within ERCOT.

- Margins from Off-system Sales decreased $11 million due to a $6 million decrease in margin sharing under the SIA and a $5 million decrease in margins from optimization activities. See the "Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement" section of Note 3.
- Transmission Revenues decreased $5 million primarily due to reduced affiliated transmission fees resulting from the elimination of the affiliated OATT in 2005.
- Other revenues decreased $39 million primarily resulting from the completion of certain third party construction projects related to work performed for the Lower Colorado River Authority.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses decreased $38 million primarily due to lower expenses related to the completion of certain third party construction projects related to work performed for the Lower Colorado River Authority.

Income Taxes

The decrease in Income Tax Expense of $17 million is primarily due to a decrease in pretax book income.

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook, except for Fitch which has us on a negative outlook. Our current ratings are as follows:

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

Financing Activity

There were no long-term debt issuances or retirements during the first nine months of 2006.

Liquidity

We have solid investment grade ratings, which provide us ready access to capital markets in order to issue new debt or refinance long-term debt maturities. In addition, TNC participates in the Utility Money Pool and TNGC participates in the Nonutility Money Pool, both of which provide access to AEP's liquidity.

Summary Obligation Information

A summary of our contractual obligations is included in our 2005 Annual Report and has not changed significantly from year-end except for Energy and Capacity Purchase Contracts. We exited both the SIA and CSW Operating Agreement, eliminating our future obligation for Energy and Capacity Purchase Contracts. See "Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement" section of Note 3.

Significant Factors

Litigation and Regulatory Activity

In the ordinary course of business, we are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot state what the eventual outcome of these proceedings will be, or what the timing of the amount of any loss, fine or penalty may be. Management does, however, assess the probability of loss for such contingencies and accrues a liability for cases which have a probable likelihood of loss and the loss amount can be estimated. For details on our pending litigation and regulatory proceedings, see Note 4 - Rate Matters, Note 6 - Customer Choice and Industry Restructuring and Note 7 - Commitments and Contingencies in our 2005 Annual Report. Also, see Note 3 - Rate Matters, Note 4 - Customer Choice and Industry Restructuring and Note 5 - Commitments and Contingencies in the "Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries" section. Adverse results in these proceedings have the potential to materially affect our results of operations, financial condition and cash flows.

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

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 2005 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, 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

The following two tables summarize the various mark-to-market (MTM) positions included in our condensed consolidated balance sheet as of September 30, 2006 and the reasons for changes in our total MTM value as compared to December 31, 2005.

Reconciliation of MTM Risk Management Contracts to
Condensed Consolidated Balance Sheet
As of September 30, 2006
(in thousands)

	MTM Risk Management Contracts	Cash Flow Hedges	Total
Current Assets	$ -	$ -	$ -
Noncurrent Assets	-	-	-
Total MTM Derivative Contract Assets	-	-	-
Current Liabilities	(2,138)	-	(2,138)
Noncurrent Liabilities	-	(2,057)	(2,057)
Total MTM Derivative Contract Liabilities	(2,138)	(2,057)	(4,195)
Total MTM Derivative Contract Net Assets (Liabilities)	$ (2,138)	$ (2,057)	$ (4,195)

MTM Risk Management Contract Net Assets (Liabilities)
Nine Months Ended September 30, 2006
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2005	$ 2,698
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(585)
Fair Value of New Contracts at Inception When Entered During the Period (a)	-
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period	-
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts	-
Changes in Fair Value Due to Market Fluctuations During the Period (b)	(3,437)
Changes Due to SIA and CSW Operating Agreement (c)	(814)
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	-
Total MTM Risk Management Contract Net Assets (Liabilities)	(2,138)
Net Cash Flow Hedge Contracts	(2,057)
Total MTM Risk Management Contract Net Assets (Liabilities) at September 30, 2006	$ (4,195)

(a) 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.
(b) Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
(c) See "Allocation Agreement between AEP East companies and AEP West companies" section of this Management's Financial Discussion and Analysis.
(d) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Condensed Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.

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

	Remainder 2006	2007	2008	2009	2010	After 2010	Total
Prices Actively Quoted - Exchange Traded Contracts	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Prices Provided by Other External Sources - OTC Broker Quotes (a)	(2,138)	-	-	-	-	-	(2,138)
Prices Based on Models and Other Valuation Methods (b)	-	-	-	-	-	-	-
Total	$ (2,138)	$ -	$ -	$ -	$ -	$ -	$ (2,138)

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

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

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 to mitigate the impact of these fluctuations on the future cash flows from assets. We do not hedge all commodity price risk.

The following table provides the detail on designated, effective cash flow hedges included in AOCI on our Condensed Consolidated Balance Sheets and the reasons for the changes from December 31, 2005 to September 30, 2006. Only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts that are not designated as effective cash flow hedges are marked-to-market and included in the previous risk management tables. All amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Nine Months Ended September 30, 2006

(in thousands)

		Power
Beginning Balance in AOCI December 31, 2005	$	(111)
Changes in Fair Value		(1,337)
Impact Due to Change in SIA (a)		98
Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled		13
Ending Balance in AOCI September 30, 2006	$	(1,337)

(a) See "Allocation Agreement between AEP East companies and AEP West companies" section of this Management's Financial Discussion and Analysis.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is zero.

Credit Risk

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

VaR Associated with Risk Management Contracts

We use a risk measurement model, which calculates Value at Risk (VaR) to measure our commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, at September 30, 2006, a near term typical change in commodity prices is not expected to have a material effect on our results of operations, cash flows or financial condition.

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

Nine Months Ended September 30, 2006 (in thousands)				Twelve Months Ended December 31, 2005 (in thousands)			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$-	$23	$4	$-	$55	$92	$44	$16

VaR Associated with Debt Outstanding

We also utilize a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. 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 $11 million and $13 million at September 30, 2006 and December 31, 2005, 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 operations or financial position.

AEP TEXAS NORTH COMPANY AND SUBSIDIARY
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2006 and 2005
(in thousands)
(Unaudited)

	Three Months Ended		Nine Months Ended	
	2006	**2005**	**2006**	**2005**
REVENUES				
Electric Generation, Transmission and Distribution	$ 79,805	$ 111,107	$ 219,681	$ 280,195
Sales to AEP Affiliates	7,711	13,019	25,596	37,189
Other	246	1,971	149	42,324
TOTAL	87,762	126,097	245,426	359,708
EXPENSES				
Fuel and Other Consumables for Electric Generation	14,016	13,433	33,175	37,772
Purchased Electricity for Resale	14,606	34,425	60,343	88,367
Purchased Electricity from AEP Affiliates	2,436	1	3,978	23
Other Operation	19,003	18,878	59,192	97,135
Maintenance	5,088	5,954	15,505	15,093
Depreciation and Amortization	10,767	10,435	31,172	30,952
Taxes Other Than Income Taxes	5,478	6,047	16,874	17,465
TOTAL	71,394	89,173	220,239	286,807
OPERATING INCOME	16,368	36,924	25,187	72,901
Other Income (Expense):				
Interest Income	203	890	542	1,688
Allowance for Equity Funds Used During Construction	146	137	636	366
Interest Expense	(4,472)	(4,931)	(13,351)	(14,784)
INCOME BEFORE INCOME TAXES	12,245	33,020	13,014	60,171
Income Tax Expense	3,799	10,716	1,326	18,469
NET INCOME	8,446	22,304	11,688	41,702
Preferred Stock Dividend Requirements	26	26	78	78
Gain on Reacquired Preferred Stock	-	-	2	-
EARNINGS APPLICABLE TO COMMON STOCK	$ 8,420	$ 22,278	$ 11,612	$ 41,624

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

AEP TEXAS NORTH COMPANY AND SUBSIDIARY
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Nine Months Ended September 30, 2006 and 2005
(in thousands)
(Unaudited)

	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			(20,827)		(20,827)
Preferred Stock Dividends			(78)		(78)
TOTAL					289,516
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $698				(1,296)	(1,296)
NET INCOME			41,702		41,702
TOTAL COMPREHENSIVE INCOME					40,406
SEPTEMBER 30, 2005	$ 137,214	$ 2,351	$ 191,781	$ (1,424	