TCC Unbundled Cost of Service (UCOS) Appeal

The UCOS proceeding established the unbundled regulated wires rates to be effective when retail electric competition began. TCC placed new T&D rates into effect as of January 1, 2002 based upon an order issued by the PUCT resulting from TCC's UCOS proceeding. Certain PUCT rulings, including the initial determination of stranded costs, the requirement to refund TCC's excess earnings, the regulatory treatment of nuclear insurance and the distribution rates charged municipal customers, were appealed to the Travis County District Court by TCC and other parties to the proceeding. The District Court issued a decision on June 16, 2003, upholding the PUCT's UCOS order with one exception. The Court ruled that the refund of the 1999 through 2001 excess earnings, solely as a credit to nonbypassable T&D rates charged to REPs, discriminates against residential and small commercial customers and is unlawful. Management estimates that the adverse effect of a decision to reduce the PTB rates for the period prior to the sale of the AEP REPs is approximately $11 million pretax. The District Court decision was appealed to the Third Court of Appeals by TCC and other parties. Based on advice of counsel, management believes that it will ultimately prevail on appeal. If the District Court's decision is ultimately upheld on appeal or the Court of Appeals reverses the District Court on issues adverse to TCC, it could have an adverse effect on future results of operations and cash flows.

TCC and TNC ERCOT Price-to-Beat (PTB) Fuel Factor Appeal

Several parties including the Office of Public Utility Counsel and cities served by both TCC and TNC appealed the PUCT's December 2001 orders establishing initial PTB fuel factors for Mutual Energy CPL and Mutual Energy WTU. In June 2003, the Court ruled that the PUCT lacked sufficient evidence to include unaccounted for energy in the fuel factor, that the PUCT improperly shifted the burden of proof from the company to intervening parties and that the record lacked substantial evidence on the effect of loss of load due to retail competition on generation requirements. The amount of unaccounted for energy built into the PTB fuel factors was approximately $3 million for Mutual Energy WTU. The Court upheld the initial PTB orders on all other issues. At this time, management is unable to estimate the potential financial impact related to the loss of load issue. Management believes, based on the advice of counsel, that the PUCT's original decision will ultimately be upheld. If the court's decisions are ultimately upheld, the PUCT could reduce the PTB fuel factors charged to retail customers in the years 2002 through 2004 resulting in an adverse effect on TCC's and TNC's future results of operations and cash flows.

PSO Rate Review

PSO is involved in a commission staff-initiated rate review before the OCC. In that proceeding, PSO made a filing seeking to increase its base rates, while various other parties made recommendations to reduce PSO's base rates. The annual rate reduction recommendations ranged between $15 million and $36 million. In March 2005, a settlement was negotiated and approved by the ALJ. Pending approval by the OCC, the settlement provides for a $7 million base rate reduction partially offset by a $6 million reduction in annual depreciation expense. The settlement also provides for recovery of $9 million of deferred fuel and the continuation of the vegetation management rider. In addition, the settlement eliminates a $9 million annual merger savings rate reduction rider at the end of December 2005. Finally, the settlement stipulates that PSO may not file for a base rate increase before April 1, 2006. The OCC did not approve the settlement in time for implementation of new base rates in May 2005 as agreed to by the parties, which voids the settlement. The OCC issued an Order approving the stipulation on May 2, 2005 with one exception. The Order approves the implementation of new base rates in June 2005 versus the stipulation date of May 2005.

RTO Formation/Integration

Prior to joining PJM, the AEP East companies deferred costs incurred under FERC orders to originally form a new RTO, (the Alliance) and subsequently to join an existing RTO (PJM). In 2004, we requested permission to amortize beginning January 1, 2005 the $18 million of deferred non-PJM billed formation/integration costs over 15 years and the $17 million of deferred PJM-billed integration costs, but we did not propose an amortization period for the PJM-billed costs in the application. The FERC has approved our application.

In January 2005, the AEP East companies began amortizing their deferred non-PJM billed costs over 15 years and the deferred PJM-billed integration costs over 10 years. The total amortization related to such costs was $1 million in the first quarter of 2005. As of March 31, 2005, the AEP East Companies have $34 million of deferred unamortized RTO formation/integration costs.

On March 8, 2005, we jointly filed with other utilities a request with the FERC to recover deferred PJM-billed integration costs of $17 million from all load-serving entities in the PJM RTO over a ten-year period starting January 1, 2005. On March 31, 2005, we also filed a request for a revised network integration transmission service revenue requirement for the AEP zone of PJM. Included in the costs reflected in that revenue requirement was the budgeted 2005 amortization of our deferred non-PJM billed Alliance RTO formation and PJM integration costs. The AEP East companies will be responsible for paying most of the amounts allocated by the FERC to the AEP East zone since the costs are attributable to their internal load.

Although several parties have filed protests of the joint filing to recover the deferred PJM-billed integration costs, we believe that it is probable that the FERC will ultimately approve recovery of the PJM-billed integration costs through the PJM OATT and that the FERC will grant a long enough amortization period to allow us to recover the deferred non-PJM billed Alliance RTO formation and PJM integration costs in the AEP East retail jurisdictions. If the FERC issues an adverse ruling, future results of operations and cash flows could be adversely affected.

FERC Order on Regional Through and Out Rates

A load-based transitional transmission rate mechanism called SECA became effective December 1, 2004 to mitigate the loss of revenues due to the FERC's elimination of through and out (T&O) transmission rates. Billing statements from PJM for the first quarter of 2005 did not reflect any credits to AEP for SECA revenues. Based upon the SECA transition rate methodology approved by the FERC, AEP accrued $26 million of SECA revenue in the first quarter of 2005 and has a receivable for SECA revenues of $37 million at March 31, 2005. SECA billings by PJM crediting AEP for their SECA revenue are scheduled to begin in May 2005 with retroactive adjustments to be billed by PJM in June and July 2005.

In a March 2005 FERC filing, we proposed an increase in the rate for network integration transmission service, as well as rates for other ancillary services. The primary customers of these services are the municipal and cooperative wholesale entities that have load delivery points in the AEP zone of PJM. As proposed, the rates will automatically increase to reflect the loss of SECA transition rates on April 1, 2006.

The AEP East companies received approximately $196 million of T&O rate revenues for the twelve months ended September 30, 2004, the twelve months prior to AEP joining PJM. The portion of those revenues associated with transactions for which the T&O rate was eliminated and replaced by SECA transition rates was $171 million. At this time, management is unable to predict whether the SECA transition rates will fully compensate the AEP East companies for their lost T&O revenues for the period December 1, 2004 through March 31, 2006 and whether, effective with the expiration of the SECA transition rates on March 31, 2006, the resultant increase in the AEP East zonal transmission rates applicable to AEP's internal load will be sufficient to replace the SECA transition rate revenues and whether the new rates will be recoverable on a timely basis in the AEP East state retail jurisdictions and from wholesale customers within the AEP zone. If the SECA transition rates do not fully compensate AEP for its lost T&O revenues through March 31, 2006, if AEP zonal rates are not sufficiently increased by the FERC after March 31, 2006, or if any increase in the AEP East companies' transmission expenses from higher AEP zonal rates are not fully recovered in retail and wholesale rates on a timely basis, future results of operations, cash flows and financial condition could be materially affected.

Hold Harmless Proceeding

In a July 2002 order conditionally accepting our choice to join PJM, the FERC directed us, ComEd, MISO and PJM to propose a solution that would effectively hold harmless the utilities in Michigan and Wisconsin from any adverse effects associated with loop flows or congestion resulting from us and ComEd joining PJM instead of MISO.

In July 2004, AEP and PJM filed jointly with the FERC a hold-harmless proposal. In September 2004, the FERC accepted and suspended the new proposal that became effective October 1, 2004, subject to refund and to the outcome of a hearing on the appropriate compensation, if any, to the Michigan and Wisconsin utilities. A hearing is scheduled for May 2005.

The Michigan and Wisconsin utilities have presented studies that show estimated adverse effects to utilities in the two states in the range of $60 million to $70 million over the term of the agreement for AEP and ComEd. The recent supplemental filing by the Michigan companies shows estimated adverse effects to utilities in Michigan of up to $50 million over the term of agreement. AEP and ComEd have presented studies that show no adverse effects to the Michigan and Wisconsin utilities. ComEd has separately settled this issue with the Michigan and Wisconsin utilities for a one time total payment of approximately $5 million, which was approved by the FERC. On December 27, 2004, AEP and the Wisconsin utilities jointly filed a settlement that resolves all hold-harmless issues for a one-time payment of $250,000 that was approved by the FERC on March 7, 2005. On April 25, 2005, AEP and International Transmission Company in Michigan filed a settlement that resolves all hold-harmless issues for a one-time payment of $120,000. Settlement negotiations are in progress with the remaining Michigan companies.

At this time, management is unable to predict the outcome of this proceeding. AEP will support vigorously its positions before the FERC. If the FERC ultimately approves a significant hold-harmless payment to the Michigan utilities, it would adversely impact results of operations and cash flows.

4. CUSTOMER CHOICE AND INDUSTRY RESTRUCTURING

We are affected by customer choice initiatives and industry restructuring. The Customer Choice and Industry Restructuring note in our 2004 Annual Report should be read in conjunction with this report in order to gain a complete understanding of material customer choice and industry restructuring matters without significant changes since year-end. The following paragraphs discuss significant current events related to customer choice and industry restructuring and update the 2004 Annual Report.

OHIO RESTRUCTURING

On January 26, 2005, the PUCO approved Rate Stabilization Plans for CSPCo and OPCo (the Ohio companies). The plans provided, among other things, for CSPCo and OPCo to raise their generation rates by 3% and 7%, respectively, in 2006, 2007 and 2008 and provided for up to 4% of additional annual generation rate increases based on supporting the need for additional revenues. The plans also provided that the Ohio companies could recover in 2006, 2007 and 2008 environmental carrying costs and PJM RTO costs from 2004 and 2005 related to their obligation as the Provider of Last Resort in Ohio's customer choice program. First quarter of 2005 pretax earnings were increased by $13 million for CSPCo and $32 million for OPCo as a result of implementing this provision of the Rate Stabilization Plans. Of these amounts approximately $8 million for CSPCo and $21 for OPCo relate to 2004 environmental carrying costs and RTO costs.

In February 2005, various intervenors filed applications for rehearing with the PUCO regarding their approval of the rate stabilization plans. On March 23, 2005, the PUCO denied all applications for rehearing. In April 2005, an intervenor filed an appeal to the Ohio Supreme Court. Management cannot predict the ultimate impact appeal proceedings will have on future results of operations and cash flows.

TEXAS RESTRUCTURING

The stranded cost recovery process in Texas continues with the principal remaining component of the process being the PUCT's determination and approval of TCC's net stranded generation costs and other recoverable true-up items in TCC's future true-up filing. TCC has asked permission from the PUCT to file its True-up Proceeding after the sales of its interest in STP have been concluded, with only the ownership interest in Oklaunion remaining to be settled. If the request is approved, it is anticipated that TCC's True-up Proceeding will be filed during the second quarter of 2005 seeking recovery of its net regulatory asset of $1.6 billion for its net stranded cost and other true-up items, which it believes the Texas Restructuring Legislation allows.

The Components of TCC's Net True-up Regulatory Asset as of March 31, 2005 and December 31, 2004 are:

	TCC	
	March 31, 2005	December 31, 2004
	(in millions)	
Stranded Generation Plant Costs	$ 898	$ 897
Net Generation-related Regulatory Asset	249	249
Unrefunded Excess Earnings	(6)	(10)
Net Stranded Generation Costs	1,141	1,136
Carrying Costs on Stranded Generation Plant Costs	205	225
Net Stranded Generation Costs Designated for Securitization	1,346	1,361
Wholesale Capacity Auction True-up	483	483
Carrying Costs on Wholesale Capacity Auction True-up	91	77
Retail Clawback	(61)	(61)
Deferred Over-recovered Fuel Balance	(215)	(212)
Net Other Recoverable True-up Amounts	298	287
Total Recorded Net True-up Regulatory Asset	$ 1,644	$ 1,648

The Components of TNC's Net True-up Regulatory Liability as of March 31, 2005 and December 31, 2004 are:

	TNC	
	March 31, 2005	December 31, 2004
	(in millions)	
Retail Clawback	$ (14)	$ (14)
Deferred Over-recovered Fuel Balance	(5)	(4)
Total Recorded Net True-up Regulatory Liability	$ (19)	$ (18)

TCC Fuel Reconciliation

On April 14, 2005, the PUCT ruled that specific energy-only purchased power contracts included a capacity component which is not recoverable in fuel rates. In the first quarter of 2005, TCC recorded a provision for fuel revenue refund of $3 million, inclusive of interest, for this decision and continued to accrue interest on the deferred over-recovered fuel balance. This provision for refund results in a deferred over-recovery balance of $215 million as of March 31, 2005.

TCC Carrying Costs on Net True-up Regulatory Assets

TCC continues to accrue a carrying cost at the embedded 8.12% debt component rate and will continue to do so until it recovers its approved net true-up regulatory asset. In a nonaffiliated utility's securitization proceeding, the PUCT issued an order in March 2005 that resulted in a reduction in its carrying costs based on a methodology detailed in the order for calculating a cost-of-money benefit related to Accumulated Deferred Federal Income Taxes (ADFIT) on TCC's net stranded cost and other true-up items which was applied retroactively to January 1, 2004. In the first quarter of 2005, TCC accrued carrying costs of $21 million which was more than offset by an adjustment based on this order of $27 million. The net reduction of $6 million in carrying costs is included in Other Income in the first quarter of 2005 on the accompanying Consolidated Statements of Income.

As of March 31, 2005, TCC has computed carrying costs of $450 million of which $296 million was recognized as income in 2004 and the first quarter of 2005. The remaining equity component of the carrying costs of $154 million will be recognized in income as collected.

TCC Unrefunded Excess Earnings

At December 31, 2004, TCC had approximately $10 million of unrefunded excess earnings. In the first quarter of 2005, TCC refunded an additional $4 million reducing its unrefunded excess earnings to $6 million.

TCC True-up Proceeding

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

The nonaffiliated utility's March order also provided for the present value of the cost free capital benefits of ADFIT associated with stranded generation costs to be offset against other recoverable true-up amounts when establishing the competition transition charges (CTC). TCC estimates its present value ADFIT benefit to be $212 million based on its current net true-up regulatory asset. TCC performed a probability of recovery impairment test on its net true-up regulatory asset taking into account the treatment ordered by the PUCT in the nonaffiliated utility's order and determined that the projected cash flows from the transition charges were more than sufficient to recover TCC's entire net true-up regulatory asset. As a result, no impairment has been recorded. Barring any future disallowances to TCC's net recoverable true-up regulatory asset in its True-up Proceeding, TCC expects to amortize its total net true-up regulatory asset over recovery periods to be established by the PUCT in proceedings subsequent to TCC's True-up Proceeding.

We believe that our recorded net true-up regulatory asset of $1.6 billion at March 31, 2005 is recoverable under the Texas Restructuring Legislation; however, we anticipate that other parties will contend that material amounts of stranded costs should not be recovered. To the extent decisions of the PUCT in TCC's future True-up Proceeding differ from our interpretation and application of the Texas Restructuring Legislation and our evaluation of other true-up orders of nonaffiliated companies, additional material disallowances and reductions of recorded carrying costs are possible, which could have a material adverse effect on future results of operations, cash flows and possibly financial condition.

TNC True-Up Proceeding

In January 2005, intervenors made various recommendations including an increase in excess earnings of $5 million and a T&D rate reduction of $3 million annually. The intervenors also recommended that TNC's fuel over-recovery should be increased by $2 million. TNC is awaiting a PUCT decision and order and has recorded no disallowances based on intervenor contentions.

In 2004, TNC appealed to the state and federal courts the PUCT's order in its final fuel reconciliation covering the period from July 2000 through December 31, 2001. In March 2005, the ALJ made certain recommendations regarding the deferred fuel balance resulting in an additional provision for refund of $1 million, which results in an over-recovery amount of $5 million. TNC will pursue vigorously its appeals, but cannot predict their outcome.

5. COMMITMENTS AND CONTINGENCIES

As discussed in the Commitments and Contingencies note within our 2004 Annual Report, we continue to be involved in various legal matters. The 2004 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 2004 Annual Report. The matters discussed in the 2004 Annual Report without significant changes in status since year-end include, but are not limited to, (1) carbon dioxide public nuisance claims, (2) nuclear matters, (3) construction commitments, (4) potential uninsured losses, (5) shareholder lawsuits, (6) coal transportation dispute, (7) Bank of Montreal Claim and (8) FERC long-term contracts. See disclosure below for significant matters with changes in status subsequent to the disclosure made in our 2004 Annual Report.

Environmental

Federal EPA Complaint and Notice of Violation

The Federal EPA and a number of states have alleged APCo, CSPCo, I&M, OPCo and other nonaffiliated utilities modified certain units at coal-fired generating plants in violation of the new source review 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.

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 per day per violation at each generating unit ($25,000 per day prior to January 30, 1997). In 2001, the District Court ruled claims for civil penalties based on activities that occurred more than five years before the filing date of the complaints cannot be imposed. There is no time limit on claims for injunctive relief.

In June 2004, the Federal EPA issued a Notice of Violation (NOV) in order to "perfect" its complaint in the pending litigation. The NOV expands the number of alleged "modifications" undertaken at the Amos, Cardinal, Conesville, Kammer, Muskingum River, Sporn and Tanners Creek plants during scheduled outages on these units from 1979 through the present. Approximately one-third of the allegations in the NOV are already contained in allegations made by the states or the special interest groups in the pending litigation. The Federal EPA filed a motion to amend its complaint and to expand the scope of the pending litigation. The AEP subsidiaries opposed that motion. In September 2004, the judge disallowed the addition of claims to the pending case. The judge also granted motions to dismiss a number of allegations in the original filing. Subsequently, the Federal EPA and eight Northeastern states each filed an additional complaint containing the same allegations against the Amos and Conesville plants that the judge disallowed in the pending case. These complaints have been assigned to the same judge in the Southern District Court. AEP filed an answer to the complaint in January 2005, denying the allegations and stating its defenses.

In August 2003, the District Court issued a decision following a liability trial in a case pending in the Southern District of Ohio against Ohio Edison Company, a nonaffiliated utility. The District Court held that replacements of major boiler and turbine components that are infrequently performed at a single unit, that are performed with the assistance of outside contractors, that are accounted for as capital expenditures, and that require the unit to be taken out of service for a number of months are not "routine" maintenance, repair, and replacement. The District Court also held that a comparison of past actual emissions to projected future emissions must be performed prior to any nonroutine physical change in order to evaluate whether an emissions increase will occur, and that increased hours of operation that are the result of eliminating forced outages due to the repairs must be included in that calculation. Based on these holdings, the District Court ruled that all of the challenged activities in that case were not routine, and that the changes resulted in significant net increases in emissions for certain pollutants. A settlement between Ohio Edison, the Federal EPA and other parties to the litigation will avoid further litigation and result in expenditures at its plant.

Management believes that the Ohio Edison decision fails to properly evaluate and apply the applicable legal standards. The facts in our case also vary widely from plant to plant.

In August 2003, the District Court for the Middle District of South Carolina issued a decision in a case pending against Duke Energy Corporation, a nonaffiliated utility. The District Court set forth the legal standards that will be applied at the trial in that case. The District Court determined that the Federal EPA bears the burden of proof on the issue of whether a practice is "routine maintenance, repair, or replacement" and on whether or not a "significant net emissions increase" results from a physical change or change in the method of operation at a utility unit. However, the Federal EPA must consider whether a practice is "routine within the relevant source category" in determining if it is "routine." Further, the Federal EPA must calculate emissions by determining first whether a change in the maximum achievable hourly emission rate occurred as a result of the change, and then must calculate any change in annual emissions holding hours of operation constant before and after the change. The Federal EPA requested reconsideration of this decision, or in the alternative, certification of an interlocutory appeal to the Fourth Circuit Court of Appeals. The District Court denied the Federal EPA's motion. In April 2004, the parties filed a joint motion for entry of final judgment, based on stipulations of relevant facts that eliminated the need for a trial, but preserving plaintiffs' right to seek an appeal of the federal prevention of significant deterioration (PSD) claims. On April 14, 2004, the Court entered final judgment for Duke Energy on all of the PSD claims made in the amended complaints, and dismissed all remaining claims with prejudice. The United States subsequently filed a notice of appeal to the Fourth Circuit Court of Appeals. The case is fully briefed and oral argument was heard in February 2005.

In June 2003, the United States Court of Appeals for the 11th Circuit issued an order invalidating the administrative compliance order issued by the Federal EPA to the Tennessee Valley Authority (TVA) for alleged CAA violations. The 11th Circuit determined that the administrative compliance order was not a final agency action, and that the enforcement provisions authorizing the issuance and enforcement of such orders under the CAA are unconstitutional. The United States filed a petition for certiorari with the United States Supreme Court and on May 3, 2004, that petition was denied.

In June 2003, the United States Court of Appeals for the District of Columbia Circuit granted a petition by the Utility Air Regulatory Group (UARG), of which our subsidiaries are members, to reopen petitions for review of the 1980 and 1992 Clean Air Act rulemakings that are the basis for the Federal EPA claims in our case and other related cases. On August 4, 2003, UARG filed a motion to separate and expedite review of their challenges to the 1980 and 1992 rulemakings from other unrelated claims in the consolidated appeal. The Circuit Court denied that motion on September 30, 2003. The central issue in these petitions concerns the lawfulness of the emissions increase test, as currently interpreted and applied by the Federal EPA in its utility enforcement actions. A decision by the D. C. Circuit Court could significantly impact further proceedings in our case. Briefing continues in this case and oral argument was held in January 2005.

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

In September 2004, the Sierra Club filed a complaint under the citizen suit provisions of the CAA against DPL, Inc., Cinergy Corporation, CSPCo, and The Dayton Power & Light Company in the United States District Court for the Southern District of Ohio alleging that violations of the PSD and New Source Performance Standards requirements of the CAA and the opacity provisions of the Ohio state implementation plan occurred at the J.M. Stuart Station, and seeking injunctive relief and civil penalties. CSPCo owns a 26% share of the J.M. Stuart Station. The owners have filed a motion to dismiss portions of the complaint, based primarily upon the federal statute of limitations. In March 2005, in an unrelated case alleging new source review permitting claims against TVA, the court granted a motion to dismiss the claims against TVA on similar grounds. The owners have advised the court of this new decision. We believe the allegations in the complaint are without merit, and intend to defend vigorously this action. Management is unable to predict the timing of any future action by the special interest group or the effect of such actions on future operations or cash flows.

We are unable to estimate the loss or range of loss related to the contingent liability 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, any capital and operating costs of additional pollution control equipment that may be required, as well as any penalties imposed, would adversely affect future results of operations, cash flows and possibly financial condition unless such costs can be recovered through regulated rates and market prices for electricity.

SWEPCo Notice of Enforcement and Notice of Citizen Suit

On July 13, 2004, two special interest groups issued a notice of intent to commence a citizen suit under the CAA for alleged violations of various permit conditions in permits issued to SWEPCo's Welsh, Knox Lee and Pirkey plants. The allegations at the Welsh Plant concern compliance with emission limitations on particulate matter and carbon monoxide, compliance with a referenced design heat input value, and compliance with certain reporting requirements. The allegations at the Knox Lee Plant relate to the receipt of an off-specification fuel oil, and the allegations at Pirkey Plant relate to testing and reporting of volatile organic compound emissions. On March 10, 2005, a complaint was filed in Federal District Court for the Eastern District of Texas by the two special interest groups, alleging violations of the CAA at Welsh Plant. SWEPCo will file a response to the complaint in May 2005.

On July 19, 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. The summary includes allegations concerning compliance with certain recordkeeping and reporting requirements, compliance with a referenced design heat input value in the Welsh permit, compliance with a fuel sulfur content limit, and compliance with emission limits for sulfur dioxide. On April 11, 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 $228,312 against SWEPCo based on alleged violations of certain representations regarding heat input and fuel characteristics in SWEPCo's permit application and the violations of certain recordkeeping and reporting requirements. SWEPCo responded to the preliminary report and petition on May 2, 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 references to a specific heat input value for each Welsh unit.

On August 13, 2004, TCEQ issued a Notice of Enforcement to SWEPCo relating to the off-specification fuel oil deliveries at the Knox Lee Plant. On April 11, 2005, TCEQ issued an Executive Director's Preliminary Report and Petition recommending the entry of an enforcement order and assessing an administrative penalty of $5,550 against SWEPCo based on alleged violations of certain permit requirements at Knox Lee. SWEPCo responded to the preliminary report and petition on May 2, 2005.

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.

Operational

Power Generation Facility

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

Dow uses a portion of the energy produced by the Facility and sells the excess energy. OPCo has 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 (expected to be approximately 270 MW). OPCo sells the purchased energy at market prices in the Entergy sub-region of the Southeastern Electric Reliability Council market.

OPCo has also agreed to sell up to approximately 800 MW of energy to SUEZ Energy Marketing NA, Inc. (formerly known as Tractebel Energy Marketing, Inc.) (TEM) for a period of 20 years under a Power Purchase and Sale Agreement dated November 15, 2000, (PPA), at a price 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 United States District Court for the Southern District of New York. We allege that TEM has breached the PPA, and we are seeking a determination of our rights under the PPA. TEM alleges that the PPA never became enforceable, or alternatively, that the PPA has already been terminated as the result of AEP's breaches. If the PPA is deemed terminated or found to be unenforceable by the court, we could be adversely affected to the extent we are unable to find other purchasers of the power with similar contractual terms and to the extent we do not fully recover claimed termination value damages from TEM. The corporate parent of TEM (SUEZ-TRACTEBEL S.A.) has provided a limited guaranty.

In November 2003, the above litigation was suspended pending final resolution in arbitration of all issues pertaining to the protocols relating to the dispatching, operation, and maintenance of the Facility and the sale and delivery of electric power products. In the arbitration proceedings, TEM argued that in the absence of mutually agreed upon protocols there were no commercially reasonable means to obtain or deliver the electric power products and therefore the PPA is not enforceable. TEM further argued that the creation of the protocols is not subject to arbitration. The arbitrator ruled in favor of TEM on February 11, 2004 and concluded that the "creation of protocols" was not subject to arbitration, but did not rule upon the merits of TEM's claim that the PPA is not enforceable. On January 21, 2005, the District Court granted AEP partial summary judgment on this issue, holding that the absence of operating protocols does not prevent enforcement of the PPA.

On March 26, 2004, OPCo requested that TEM provide assurances of performance of its future obligations under the PPA, but TEM refused to do so. As indicated above, OPCo also gave notice to TEM and declared April 2, 2004 as the "Commercial Operations Date." Despite OPCo's prior tenders of replacement electric power products to TEM beginning May 1, 2003 and despite OPCo's tender of electric power products from the Facility to TEM beginning April 2, 2004, TEM refused to accept and pay for these electric power products under the terms of the PPA. On April 5, 2004, OPCo gave notice to TEM that OPCo, (i) was suspending performance of its obligations under the PPA, (ii) would be seeking a declaration from the New York federal court that the PPA has been terminated and (iii) would be pursuing against TEM, and SUEZ-TRACTEBEL S.A. under the guaranty, damages and the full termination payment value of the PPA.

A bench trial was conducted in March and April 2005.

Merger Litigation

In 2002, the U.S. Court of Appeals for the District of Columbia ruled that the SEC did not adequately explain that the June 15, 2000 merger of AEP with CSW meets the requirements of the PUHCA and sent the case back to the SEC for further review. Specifically, the court told the SEC to revisit the basis for its conclusion that the merger met PUHCA requirements that utilities be "physically interconnected" and confined to a "single area or region." In January 2005, a hearing was held before an ALJ.

On May 3, 2005, the ALJ issued an Initial Decision concluding that the AEP System is "physically interconnected" but is not confined to a "single area or region." Therefore, the ALJ concluded that the combined AEP/CSW system does not constitute a single integrated public utility system under PUHCA. Management believes that the merger meets the requirements of PUHCA and will file a petition for review of this Initial Decision. The SEC will review the Initial Decision.

Enron Bankruptcy

In 2002, certain of our subsidiaries filed claims against Enron and its subsidiaries in the Enron bankruptcy proceeding pending in the U.S. Bankruptcy Court for the Southern District of New York. At the date of Enron's bankruptcy, certain of our subsidiaries had open trading contracts and trading accounts receivables and payables with Enron. In addition, on June 1, 2001, we purchased HPL from Enron. Various HPL-related contingencies and indemnities from Enron remained unsettled at the date of Enron's bankruptcy.

Enron Bankruptcy – Right to use of cushion gas agreements – In connection with the 2001 acquisition of HPL, we entered into an agreement with BAM Lease Company, which grants 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 also released HPL from all prior and future liabilities and obligations in connection with the financing arrangement.

After the Enron bankruptcy, HPL was informed by the BOA Syndicate 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 state court of Texas 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 court granted partial summary judgment in favor of the BOA Syndicate. HPL appealed 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 defend vigorously 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. On April 6, 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.

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 have objected to Enron's attempted rejection of these agreements and have filed an adversary proceeding contesting Enron's right to reject these agreements.

In January 2005, we sold a 98% limited partner interest in HPL. We have indemnified the buyer of the 98% interest in 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 is dependent on the ultimate resolution of the BOA dispute and the costs, if any, associated with the resolution of this matter.

Enron Bankruptcy – Commodity trading settlement disputes – In September 2003, Enron filed a complaint in the Bankruptcy Court against AEPES challenging AEP's offsetting of receivables and payables and related collateral across various Enron entities and seeking payment of approximately $125 million plus interest in connection with gas-related trading transactions. We asserted our right to offset trading payables owed to various Enron entities against trading receivables due to several of our subsidiaries. The parties are currently in nonbinding, court-sponsored mediation.

In December 2003, Enron filed a complaint in the Bankruptcy Court against AEPSC seeking approximately $93 million plus interest in connection with a transaction for the sale and purchase of physical power among Enron, AEP and Allegheny Energy Supply, LLC during November 2001. Enron's claim seeks to unwind the effects of the transaction. AEP believes it has several defenses to the claims in the action being brought by Enron. The parties are currently in nonbinding, court-sponsored mediation.

Enron Bankruptcy – Summary – The amount expensed in prior years in connection with the Enron bankruptcy was based on an analysis of contracts where AEP and Enron entities are counterparties, the offsetting of receivables and payables, the application of deposits from Enron entities and management's analysis of the HPL-related purchase contingencies and indemnifications. As noted above, Enron has challenged our offsetting of receivables and payables and there is a dispute regarding the cushion gas agreement. Although management is unable to predict the outcome of these lawsuits, it is possible that their resolution could have an adverse impact on our results of operations, cash flows or financial condition.

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 has been dismissed from the case. The plaintiff had stated an intention to amend the complaint to add an AEP subsidiary as a defendant. The plaintiff amended the complaint but did not name any AEP company as a defendant. Since then, a number of 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 were 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. We will continue to defend vigorously 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. On December 5, 2003, the Court issued its initial Pretrial Order consolidating all related cases, appointing co-lead counsel and providing for the filing of an amended consolidated complaint. In January 2004, plaintiffs filed an amended consolidated complaint. The defendants filed a motion to dismiss the complaint which the Court denied in September 2004. Plaintiffs have filed a Motion for Class Certification. The defendants, including AEP and AEPES, filed their opposition to class certification on April 8, 2005. Briefing on the issue of class certification is expected to be completed in the second quarter of 2005. Discovery is continuing in the case with a discovery cut-off date of June 30, 2005. We intend to defend vigorously against these claims.

Texas Commercial Energy, LLP Lawsuit

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

Appeals for the Fifth Circuit. In March 2005, Utility Choice, LLC and Cirro Energy Corporation filed in U.S. District Court alleging similar violations as those alleged in the TCE lawsuit. In April 2005, the defendants filed a Motion to Stay this case, pending the outcome of the appeal in the TCE case.

6. GUARANTEES

There are certain immaterial liabilities recorded for guarantees entered into subsequent to December 31, 2002 in accordance with FIN 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness to 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 have entered into standby letters of credit (LOC) with third parties. These LOCs cover gas and electricity risk management contracts, construction contracts, insurance programs, security deposits, debt service reserves and credit enhancements for issued bonds. We issued all of these LOCs in our ordinary course of business. At March 31, 2005, the maximum future payments for all the LOCs were approximately $234 million with maturities ranging from May 2005 to April 2007. As the parent of the various subsidiaries that have issued these LOCs, we hold all assets of the subsidiaries as collateral. There is no recourse to third parties in the event these LOCs are drawn.

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 has agreed, under certain conditions, to assume the capital lease obligations and term loan payments of the mining contractor, Sabine Mining Company (Sabine). In the event Sabine defaults under any of these agreements, SWEPCo's total future maximum payment exposure is approximately $51 million with maturity dates ranging from June 2005 to February 2012.

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo has agreed to provide guarantees of mine reclamation in the amount of approximately $85 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by a third party miner. At March 31, 2005, the cost to reclaim the mine in 2035 is estimated to be approximately $39 million. This guarantee ends upon depletion of reserves estimated at 2035 plus 6 years to complete reclamation.

INDEMNIFICATIONS AND OTHER GUARANTEES

Contracts

We entered 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. We cannot estimate the maximum potential exposure for any of these indemnifications executed prior to December 31, 2002 due to the uncertainty of future events. In 2004 and the first three months of 2005, we entered into several sale agreements. An update of the status of sales agreements is discussed in Note 7. These sale agreements include indemnifications with a maximum exposure of approximately $1.9 billion. 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 to receive up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair market value of the leased equipment is below the unamortized balance at the end of the lease term, we have committed to pay the difference between the fair market value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. At March 31, 2005, the maximum potential loss for this lease agreement was approximately $43 million ($28 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 an unrelated, unconsolidated leasing company to lease 875 coal-transporting aluminum railcars. The lease has an initial term of five years and may be renewed for up to three additional five-year terms, for a maximum of twenty years. We intend to renew the lease for the full twenty 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. This operating lease agreement allows us to avoid a large initial capital expenditure, and to spread our railcar costs evenly over the expected twenty-year usage.

Under the lease agreement, the lessor is guaranteed that the sale proceeds under the return-and-sale option discussed above will equal at least a lessee obligation amount specified in the lease, which declines over the term from approximately 86% to 77% of the projected fair market value of the equipment. At March 31, 2005, the maximum potential loss was approximately $31 million ($20 million, net of tax) assuming the fair market value of the equipment is zero at the end of the current lease term. The railcars are subleased for one year terms to a nonaffiliated company under an operating lease. The sublessee may renew the lease for up to three additional one-year terms. AEP has other railcar lease arrangements that do not utilize this type of structure.

7. DISPOSITIONS, DISCONTINUED OPERATIONS AND ASSETS HELD FOR SALE

DISPOSITIONS COMPLETED AND ANTICIPATED BEING COMPLETED DURING THE FIRST HALF OF 2005

Houston Pipe Line Company (Investments – Gas Operations segment)

In January 2005, we sold a 98% controlling interest in HPL, 30 BCF of working gas and working capital for approximately $1 billion, subject to a working capital and inventory true-up adjustment. We retained a 2% ownership interest in HPL and provide certain transitional administrative services to the buyer. Although the assets have been legally transferred, it is not possible to determine all costs associated with the transfer until the BOA litigation is resolved. Accordingly, we have deferred the excess of the sales price over the carrying cost of the net assets transferred as a deferred gain of $407 million as of March 31, 2005, which is reflected in Deferred Credits and Other on our accompanying Consolidated Balance Sheets. We provided an indemnity in an amount up to the purchase price to the purchaser for damages, if any, arising from litigation with BOA and a resulting inability to use the cushion gas (see "Enron Bankruptcy – Right to Use of Cushion Gas Agreements" section of Note 5). The HPL operations do not meet the criteria to be shown as discontinued operations due to continuing involvement associated with various contractual obligations. Significant continuing involvement includes cash flows from long-term gas contracts with the buyer through 2008, the cushion gas arrangement and our 2% ownership interest.

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

Pacific Hydro Limited (Investments – Other segment)

In March 2005, we signed an agreement with Acciona, S.A. for the sale of our equity investment in Pacific Hydro Limited for approximately $83 million. The sale is contingent on Acciona obtaining a controlling interest in Pacific Hydro Limited. If the sale occurs, we will recognize an estimated pretax gain of approximately $50 million.

Texas REPs (Utility Operations segment)

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

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

Texas Plants – Oklaunion Power Station (Utility Operations segment)

In January 2004, we signed an agreement to sell TCC's 7.81% share of Oklaunion Power Station for approximately $43 million (subject to closing adjustments) to an unrelated party. By May 2004, we received notice from the two nonaffiliated co-owners of the Oklaunion Power Station, announcing their decision to exercise their right of first refusal, with terms similar to the original agreement. In June 2004 and September 2004, we entered into sales agreements with both of our nonaffiliated co-owners for the sale of TCC's 7.81% ownership of the Oklaunion Power Station. These agreements are currently being challenged in Dallas County, Texas State District Court by the unrelated party with which we entered into the original sales agreement. The unrelated party alleges that one co-owner has exceeded its legal authority and that the second co-owner did not exercise its right of first refusal in a timely manner. The unrelated party has requested that the court declare the co-owners' exercise of their rights of first refusal void. We cannot predict when these issues will be resolved. We do not expect the sale to have a significant effect on our future results of operations. TCC's assets and liabilities related to the Oklaunion Power Station have been classified as Assets Held for Sale and Liabilities Held for Sale, respectively, in our Consolidated Balance Sheets at March 31, 2005 and December 31, 2004.

Texas Plants – South Texas Project (Utility Operations segment)

In February 2004, we signed an agreement to sell TCC's 25.2% share of the STP nuclear plant to an unrelated party for approximately $333 million, subject to closing adjustments. In June 2004, we received notice from co-owners of their decisions to exercise their rights of first refusal, with terms similar to the original agreement. In September 2004, we entered into sales agreements with two of our nonaffiliated co-owners for the sale of TCC's 25.2% share of the STP nuclear plant. We do not expect the sale to have a significant effect on our future results of operations. We expect the sale to close in the second quarter of 2005. TCC's assets and liabilities related to STP have been classified as Assets Held for Sale and Liabilities Held for Sale, respectively, in our Consolidated Balance Sheets at March 31, 2005 and December 31, 2004.

DISCONTINUED OPERATIONS

Certain of our operations were determined to be discontinued operations and have been classified as such for all periods presented. Results of operations of these businesses have been reclassified for the three-month periods ended March 31, 2005 and 2004 as shown in the following table:

	SEEBOARD (a)	U.K. Operations (b)	Total
2005 Revenue	$ -	$ -	$ -
2005 Pretax Income (Loss)	-	(8)	(8)
2005 Income (Loss) After tax	6	(5)	1

	Pushan Power Plant	LIG (c)	U.K. Operations	Total
2004 Revenue	$ 10	$ 160	$ 41	$ 211
2004 Pretax Income (Loss)	-	(1)	(19)	(20)
2004 Income (Loss) After tax	6	(1)	(12)	(7)

(a) Includes a tax adjustment related to the sale of SEEBOARD.
(b) Relates primarily to purchase price true-up adjustments.
(c) Includes LIG Pipeline Company and subsidiaries and Jefferson Island Storage & Hub LLC.

During the quarter ended March 31, 2004, the net increase in cash and cash equivalents of discontinued operations was $24 million, primarily from the cash flows from operating activities of the discontinued operations.

ASSETS HELD FOR SALE

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

	Texas Plants	
	March 31, 2005	December 31, 2004
Assets:	(in millions)	
Other Current Assets	$ 25	$ 24
Property, Plant and Equipment, Net	416	413
Regulatory Assets	52	48
Nuclear Decommissioning Trust Fund	143	143
Total Assets Held for Sale	$ 636	$ 628
Liabilities:		
Regulatory Liabilities	$ 1	$ 1
Asset Retirement Obligations	254	249
Total Liabilities Held for Sale	$ 255	$ 250

8. BENEFIT PLANS

Components of Net Periodic Benefit Costs

The following table provides the components of our net periodic benefit cost for the following plans for the three months ended March 31, 2005 and 2004:

	Pension Plans		Other Postretirement Benefit Plans	
	2005	2004	2005	2004
	(in millions)			
Service Cost	$ 23	$ 22	$ 11	$ 10
Interest Cost	56	56	27	29
Expected Return on Plan Assets	(77)	(72)	(23)	(20)
Amortization of Transition (Asset) Obligation	-	-	7	7
Amortization of Net Actuarial Loss	13	4	7	9
Net Periodic Benefit Cost	$ 15	$ 10	$ 29	$ 35

9. BUSINESS SEGMENTS

Our segments and their related business activities are as follows:

Utility Operations

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

Investments - Gas Operations (a)

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

Investments - UK Operations (b)

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

Investments – Other (c)

- Bulk commodity barging operations, wind farms, independent power producers and other energy supply related businesses.

(a) Operations of Louisiana Intrastate Gas, including Jefferson Island Storage, were classified as Discontinued Operations during 2003 and were sold during the third and fourth quarter of 2004, respectively. A ninety-eight percent interest in HPL was sold during the first quarter of 2005.

(b) UK Operations were classified as Discontinued Operations during 2003 and were sold during the third quarter of 2004.

(c) Four independent power producers were sold during the third and fourth quarters of 2004.

With the sale of HPL during January 2005, we have substantially completed planned disposals of all significant non-core assets. Accordingly, effective with the quarter ended March 31, 2005, certain subsidiaries representing shared service functions and costs were reclassified to Utility Operations and Investments - Other from either Investments – Other or All Other. Such reclassifications were deemed necessary given the remaining compositions of the individual segments and the nature of the shared service functions and costs. The 2004 information presented herein has been reclassified to conform to the 2005 presentation.

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

Three Months Ended March 31, 2005	Utility Operations	Investments Gas Operations	Investments UK Operations	Investments Other	All Other (a)	Reconciling Adjustments (b)	Consolidated
				(in millions)			
Revenues from:							
External Customers	$ 2,537	$ 357	$ -	$ 89	$ -	$ -	$ 2,983
Other Operating Segments	77	(73)	-	3	1	(8)	-
Total Revenues	$ 2,614	$ 284	$ -	$ 92	$ 1	$ (8)	$ 2,983
Income (Loss) Before Discontinued Operations	$ 353	$ 10	$ -	$ 5	$ (14)	$ -	$ 354
Discontinued Operations, Net of Tax	-	-	(5)	6	-	-	1
Net Income (Loss)	$ 353	$ 10	$ (5)	$ 11	$ (14)	$ -	$ 355
As of March 31, 2005							
Total Property, Plant and Equipment	$ 36,348	$ 2	$ -	$ 835	$ 3	$ -	$ 37,188
Accumulated Depreciation and Amortization	14,494	1	-	93	1	-	14,589
Total Property, Plant and Equipment - Net	$ 21,854	$ 1	$ -	$ 742	$ 2	$ -	$ 22,599
Total Assets	$ 32,655	$ 1,295	$ 597(c)	$ 1,557	$ 10,740	$ (11,747)	$ 35,097
Assets Held for Sale	636	-	-	-	-	-	636

(a) All Other includes interest, litigation and other miscellaneous parent company expenses.
(b) Reconciling Adjustments for Total Assets primarily include the elimination of intercompany advances to affiliates and intercompany accounts receivable along with the elimination of AEP's investments in subsidiary companies.
(c) Total Assets of $597 million for the Investments-UK Operations segment include $551 million in affiliated accounts receivable that are eliminated in consolidation. The majority of the remaining $46 million in assets represents cash equivalents along with value-added tax receivables.

Three Months Ended March 31, 2004	Utility Operations	Investments Gas Operations	Investments UK Operations	Investments Other	All Other (a)	Reconciling Adjustments (b)	Consolidated
				(in millions)			
Revenues from:							
External Customers	$ 2,581	$ 652	$ -	$ 131	$ -	$ -	$ 3,364
Other Operating Segments	21	24	-	16	6	(67)	-
Total Revenues	$ 2,602	$ 676	$ -	$ 147	$ 6	$ (67)	$ 3,364
Income (Loss) Before Discontinued Operations	$ 304	$ (10)	$ -	$ 4	$ (9)	$ -	$ 289
Discontinued Operations, Net of Tax	-	(1)	(12)	6	-	-	(7)
Net Income (Loss)	$ 304	$ (11)	$ (12)	$ 10	$ (9)	$ -	$ 282
As of December 31, 2004							
Total Property, Plant and Equipment	$ 36,006	$ 445	$ -	$ 832	$ 3	$ -	$ 37,286
Accumulated Depreciation and Amortization	14,355	43	-	86	1	-	14,485
Total Property, Plant and Equipment - Net	$ 21,651	$ 402	$ -	$ 746	$ 2	$ -	$ 22,801
Total Assets	$ 32,175	$ 1,789	$ 221(c)	$ 2,071	$ 8,093	$ (9,686)	$ 34,663
Assets Held for Sale	628	-	-	-	-	-	628

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

10. FINANCING ACTIVITIES

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

Company	Type of Debt	Principal Amount (in millions)	Interest Rate	Due Date
Issuances:				
APCo	Senior Unsecured Notes	$ 200	4.95%	2015
OPCo	Installment Purchase Contracts	164	Variable	2028
OPCo	Installment Purchase Contracts	54	Variable	2029
TCC	Installment Purchase Contracts	162	Variable	2030
Non-Registrant:				
AEP Subsidiary	Notes Payable	6	Variable	2009
Total Issuances		$ 586(a)		

(a) Amount indicated on statement of cash flows of $580 million is net of issuance costs and unamortized premium or discount.

Company	Type of Debt	Principal Amount (in millions)	Interest Rate	Due Date
Retirements and Principal Payments:				
AEP	Other Debt	$ 3	Variable	2007
AEP and Subsidiaries	Other	6(b)	Variable	Various
OPCo	Installment Purchase Contracts	102	6.375%	2029
OPCo	Installment Purchase Contracts	80	Variable	2028
OPCo	Installment Purchase Contracts	36	Variable	2029
OPCo	Notes Payable	1	6.81%	2008
OPCo	Notes Payable	3	6.27%	2009
SWEPCo	Notes Payable	2	4.47%	2011
SWEPCo	Notes Payable	1	Variable	2008
TCC	Senior Unsecured Notes	150	3.00%	2005
TCC	Senior Unsecured Notes	100	Variable	2005
TCC	Securitization Bonds	29	3.54%	2005
Non-Registrant:				
AEP Subsidiary	Notes Payable	3	Variable	2017
Total Retirements		$ 516(c)		

(b) Amount reflects mark-to-market of risk management contracts.
(c) Amount indicated on statement of cash flows of $510 million does not include $6 million related to the mark-to-market of risk management contracts.

Preferred Stock Redemption

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

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

Common Stock Repurchase

In March 2005, we repurchased 12.5 million shares of our outstanding common stock through an accelerated share repurchase agreement at an initial price of $34.63 per share plus transaction fees. The 12.5 million shares repurchased under the program are held in treasury and are subject to a future contingent purchase price adjustment based on the actual purchase prices paid for the common stock during the program period. Based on this adjustment, an asset of $2 million is reflected in Accounts Receivable on our Consolidated Balance Sheets as of March 31, 2005 due to the fact that the actual stock purchase prices were less than our initial payment.

AEP GENERATING COMPANY

AEP GENERATING COMPANY
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

Results of Operations

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

First Quarter of 2005 Compared to First Quarter of 2004

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

First Quarter of 2004 Net Income		$ 1.8
Change in Gross Margin:		
Wholesale Sales		(2.5)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	3.8	
Depreciation and Amortization	(0.2)	
Taxes Other Than Income Taxes	(0.1)	
Interest Charges	(0.1)	
Total Change in Operating Expenses and Other		3.4
Income Tax Expense		(0.2)
First Quarter of 2005 Net Income		$ 2.5

Gross Margin decreased $2.5 million primarily due to a decrease in operation and maintenance expense. Gross Margin fluctuates consistent with operation and maintenance expense in accordance with the unit power agreements.

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

Income Taxes

The effective tax rates for the first quarter of 2005 and 2004 were 1.8% and (9.5)%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is primarily due to amortization of investment tax credits, flow-through of book versus tax temporary differences and state income taxes. The increase in the effective tax rate is primarily due to higher pretax income in 2005.

Off-Balance Sheet Arrangement

In prior years, we entered into an off-balance sheet arrangement. Our current policy restricts the use of off-balance sheet financing entities or structures, except for 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 Discussion and Analysis" section of our 2004 Annual Report.

Significant Factors

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

Critical Accounting Estimates

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

AEP GENERATING COMPANY
STATEMENTS OF INCOME
For the Three Months Ended March 31, 2005 and 2004
(Unaudited)
(in thousands)

	2005	2004
OPERATING REVENUES	$ 66,546	$ 55,282
OPERATING EXPENSES		
Fuel for Electric Generation	35,135	21,398
Rent – Rockport Plant Unit 2	17,071	17,071
Other Operation	2,385	2,490
Maintenance	1,718	5,400
Depreciation and Amortization	5,956	5,734
Taxes Other Than Income Taxes	1,024	944
Income Taxes	936	698
TOTAL	64,225	53,735
OPERATING INCOME	2,321	1,547
Nonoperating Income	-	24
Nonoperating Expenses	64	69
Nonoperating Income Tax Credit	891	857
Interest Charges	632	532
NET INCOME	$ 2,516	$ 1,827

STATEMENTS OF RETAINED EARNINGS
For the Three Months Ended March 31, 2005 and 2004
(Unaudited)
(in thousands)

	2005	2004
BALANCE AT BEGINNING OF PERIOD	$ 24,237	$ 21,441
Net Income	2,516	1,827
Cash Dividends Declared	940	1,262
BALANCE AT END OF PERIOD	$ 25,813	$ 22,006

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

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

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

	2005	2004
ELECTRIC UTILITY PLANT		
Production	$ 682,162	$ 681,254
General	3,923	3,739
Construction Work in Progress	6,990	7,729
Total	693,075	692,722
Accumulated Depreciation and Amortization	373,165	368,484
TOTAL - NET	319,910	324,238
OTHER PROPERTY AND INVESTMENTS		
Nonutility Property, Net	119	119
CURRENT ASSETS		
Accounts Receivable – Affiliated Companies	24,248	23,078
Fuel	10,613	16,404
Materials and Supplies	6,337	5,962
Prepayments	35	-
TOTAL	41,233	45,444
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
Unamortized Loss on Reacquired Debt	4,437	4,496
Asset Retirement Obligations	1,165	1,117
Deferred Property Taxes	3,441	557
Other Deferred Charges	417	422
TOTAL	9,460	6,592
TOTAL ASSETS	$ 370,722	$ 376,393

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

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

	2005	2004
CAPITALIZATION	(in thousands)	
Common Shareholder's Equity:		
Common Stock – $1,000 par value per share:		
Authorized and Outstanding – 1,000 shares	$ 1,000	$ 1,000
Paid-in Capital	23,434	23,434
Retained Earnings	25,813	24,237
Total Common Shareholder's Equity	50,247	48,671
Long-term Debt	44,822	44,820
TOTAL	95,069	93,491
CURRENT LIABILITIES		
Advances from Affiliates	7,131	26,915
Accounts Payable:		
General	990	443
Affiliated Companies	14,405	17,905
Taxes Accrued	9,165	8,806
Interest Accrued	456	911
Obligations Under Capital Leases	285	210
Rent Accrued – Rockport Plant Unit 2	23,427	4,963
Other	102	73
TOTAL	55,961	60,226
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	23,687	24,762
Regulatory Liabilities:		
Asset Removal Costs	25,965	25,428
Deferred Investment Tax Credits	45,416	46,250
SFAS 109 Regulatory Liability, Net	12,735	12,852
Deferred Gain on Sale and Leaseback – Rockport Plant Unit 2	98,512	99,904
Obligations Under Capital Leases	12,137	12,264
Asset Retirement Obligations	1,240	1,216
TOTAL	219,692	222,676
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$ 370,722	$ 376,393

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

AEP GENERATING COMPANY
STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2005 and 2004
(Unaudited)
(in thousands)

	2005	2004
OPERATING ACTIVITIES		
Net Income	$ 2,516	$ 1,827
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Depreciation and Amortization	5,956	5,734
Deferred Income Taxes	(1,192)	(656)
Deferred Investment Tax Credits	(834)	(834)
Deferred Property Taxes	(2,884)	(2,439)
Amortization of Deferred Gain on Sale and Leaseback – Rockport Plant Unit 2	(1,392)	(1,392)
Change in Other Noncurrent Assets	(233)	91
Change in Other Noncurrent Liabilities	436	(156)
Changes in Components of Working Capital:		
Accounts Receivable	(1,170)	7,145
Fuel, Materials and Supplies	5,416	(3,687)
Accounts Payable	(2,953)	(243)
Taxes Accrued	359	4,539
Interest Accrued	(455)	(455)
Rent Accrued – Rockport Plant Unit 2	18,464	18,464
Other Current Assets	(35)	(32)
Other Current Liabilities	104	28
Net Cash Flows From Operating Activities	22,103	27,934
INVESTING ACTIVITIES		
Construction Expenditures	(1,379)	(7,525)
Net Cash Flows Used For Investing Activities	(1,379)	(7,525)
FINANCING ACTIVITIES		
Changes in Advances from Affiliates, Net	(19,784)	(19,147)
Dividends Paid	(940)	(1,262)
Net Cash Flows Used For Financing Activities	(20,724)	(20,409)
Net Increase in Cash and Cash Equivalents	-	-
Cash and Cash Equivalents at Beginning of Period	-	-
Cash and Cash Equivalents at End of Period	$ -	$ -

SUPPLEMENTAL DISCLOSURE:
Cash paid (received) for interest net of capitalized amounts was $1,021,000 and $921,000 and for income taxes was $5,439,000 and $(218,000) in 2005 and 2004, respectively.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

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

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

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY

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

Results of Operations

First Quarter of 2005 Compared to First Quarter of 2004

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

First Quarter of 2004 Net Income		$ 29
Changes in Gross Margin:		
Texas Wires	2	
Texas Supply	(35)	
Off-system Sales	(2)	
Other Revenues	(9)	
Total Change in Gross Margin		(44)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	8	
Nonoperating Income and Expense, Net	(11)	
Interest Charges	6	
Total Change in Operating Expenses and Other		3
Income Tax Expense		13
First Quarter of 2005 Net Income		$ 1

Net Income decreased $28 million to $1 million in the first quarter of 2005. The key drivers of the decrease were a $44 million decrease in gross margin partially offset by a net decrease in Other Operation and Maintenance of $8 million and by a $13 million decrease in Income Tax Expense.

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

- Texas Supply margins were $35 million less than the prior period primarily due to the loss of our largest REP customer of $77 million and loss of ERCOT reliability-must-run margins of $6 million and capacity sales of $9 million due to the sale of certain generation plants in the third quarter of 2004, offset by lower fuel expense of $57 million.
- Other Revenues for 2005 decreased $9 million in comparison to 2004 primarily due to a prior year unfavorable adjustment for affiliated OATT and ancillary services resulting from revised ERCOT data received for the years 2001 through 2003.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses decreased $8 million primarily due to a decrease in production plant operations and maintenance expenses as a result of the sale of certain generation plants in the third quarter of 2004.
- Nonoperating Income and Expense, Net decreased partially due to carrying costs on stranded cost recovery of $21 million recorded in the first quarter of 2005, offset by an adjustment of $27 million. The adjustment relates to a nonaffiliated utility's securitization proceeding where the PUCT issued an order in March 2005 that resulted in a reduction in the nonaffiliated utility's carrying costs based on a methodology detailed in the order for calculating a cost-of-money benefit related to Accumulated Deferred Federal Income Taxes retroactive to January 1, 2004.

- In addition, Nonoperating Income and Expense, Net decreased $6 million partially due to the absence of risk management activities in the first quarter of 2005.
- Interest Charges decreased $6 million primarily due to the defeasance of $112 million of First Mortgage Bonds in 2004 and the resultant deferral of the interest cost as a regulatory asset related to the cost of the sale of generation assets, the redemption of the 8% Notes Payable to Trust, long-term debt maturities and other financing activities.

Income Taxes

The effective tax rates for the first quarter of 2005 and 2004 were (906.2)% and 29.0%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to permanent differences, amortization of investment tax credits, consolidated tax savings from parent, state income taxes and federal income tax adjustments. The decrease in the effective tax rate for the comparative period is primarily due to lower pretax income in 2005, federal income tax adjustments and consolidated tax savings from parent, offset in part by a decrease in state income taxes.

Financial Condition

Credit Ratings

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

	Moody's	S&P	Fitch
First Mortgage Bonds	Baa1	BBB	A
Senior Unsecured Debt	Baa2	BBB	A-

Cash Flow

Cash flows for the three months ended March 31, 2005 and 2004 were as follows:

	2005	2004
	(in thousands)	
Cash and cash equivalents at beginning of period	$ -	$ 760
Cash flows from (used for):		
Operating activities	(121,316)	25,873
Investing activities	3,997	4,582
Financing activities	118,292	(29,182)
Net increase in cash and cash equivalents	973	1,273
Cash and cash equivalents at end of period	$ 973	$ 2,033

Operating Activities

Our net cash flows used for operating activities were $121 million for the first three months of 2005. We produced income of $1 million during the period including noncash expense items of $29 million for Depreciation and Amortization and $(30) million for Deferred Property Taxes. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in these asset and liability accounts relate to a number of items; the most significant are decreases in Accounts Payable, Taxes Accrued and Interest Accrued offset in part by an increase in Accounts Receivable, Net. Accounts Payable decreased $41 million primarily due to lower vendor related payables and lower third party energy transactions. Taxes Accrued decreased $118 million primarily due to a Federal income tax payment offset by the annual tax accruals related to 2005 property taxes. Interest Accrued decreased $22 million primarily due to interest payments on debentures and senior unsecured notes offset by monthly accruals.

Our net cash flows from operating activities were $26 million for the first three months of 2004. We produced income of $29 million during the period including noncash expense items of $29 million for Depreciation and Amortization and $(34) million for Deferred Property Taxes. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The activity in these asset and liability accounts relates to a number of items; the most significant is an increase in Taxes Accrued offset by decreases in Accounts Payable and Interest Accrued. Taxes Accrued increased $32 million primarily due to the annual tax accruals related to property taxes net of a payment in 2004 and by a decrease in Federal income tax refunds. Accounts Payable decreased $14 million primarily due to decreased trading related payables and fewer fuel related shipments. Interest Accrued decreased $20 million primarily due to interest payments on debentures and senior unsecured notes offset by monthly accruals.

Investing Activities

Cash Flows From Investing Activities were $4 million in 2005 primarily due to a decrease of $32 million in Other Cash Deposits, Net related to principal payments on transition funding bonds offset by Construction Expenditures of $28 million related to projects for improved transmission and distribution service reliability. For the remainder of 2005, we expect our Construction Expenditures to be approximately $180 million.

Cash Flows From Investing Activities were $5 million in 2004 primarily due to a decrease of $28 million in Other Cash Deposits, Net related to principal payments on transition funding bonds offset by Construction Expenditures of $24 million related to projects for improved transmission and distribution service reliability.

Financing Activities

Cash Flows From Financing Activities of $118 million in 2005 were due to a $238 million increase in Advances to/from Affiliates, Net and issuances of Installment Purchase Contracts of $159 million offset by retirements of Senior Unsecured Note Payables and Securitization Bonds of $279 million.

Cash Flows Used for Financing Activities of $29 million in 2004 were due to retirements of long-term debt, payment of dividends and increased Advances to Affiliates.

Financing Activity

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

Issuances

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in thousands)	(%)	
Installment Purchase Contract	$111,700	Variable	2030
Installment Purchase Contract	50,000	Variable	2030

Retirements

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in thousands)	(%)	
Senior Unsecured Note Payable	$150,000	3.00	2005
Senior Unsecured Note Payable	100,000	Variable	2005
Securitization Bonds	29,386	3.54	2005

Liquidity

We have solid investment grade ratings, which provide us ready access to capital markets in order to refinance long-term debt maturities. In addition, we participate in the AEP Utility Money Pool, which provides access to AEP's liquidity. Finally, we expect to receive asset sale proceeds of approximately $333 million in the first half of 2005, subject to resolution of the rights of first refusal issues and obtaining the necessary regulatory approvals.

Significant Factors

Texas Restructuring

The stranded cost recovery process in Texas continues with the principal remaining component of the process being the PUCT's determination and approval of our net stranded generation costs and other recoverable true-up items in our future true-up filing. We have asked permission from the PUCT to file our True-up Proceeding after the sales of our interest in STP have been concluded. If the request is approved, it is anticipated that our True-up Proceeding will be filed during the second quarter of 2005 seeking recovery of our net regulatory asset of $1.6 billion for our net stranded cost and other true-up items which we believe the Texas Restructuring Legislation allows.

We continue to accrue a carrying cost at the embedded 8.12% debt component rate and will continue to do so until we recover our approved net true-up regulatory asset. In a nonaffiliated utility's securitization proceeding, the PUCT issued an order in March 2005 further clarifying how the amounts are to be calculated. This resulted in a reduction in our accrued carrying costs based on the methodology detailed in the order for calculating a cost-of-money benefit related to Accumulated Deferred Federal Income Taxes (ADFIT) on our net stranded cost and other true-up items retroactive to January 1, 2004. In the first quarter of 2005, we accrued carrying costs of $21 million, which was more than offset by an adverse adjustment of $27 million based on this order. The net reduction of $6 million in carrying costs is included in Nonoperating Income in the first quarter of 2005 on our accompanying Consolidated Statements of Income.

As of March 31, 2005, we have computed carrying costs of $450 million of which $296 million was recognized as income in 2004 and the first quarter of 2005. The remaining equity component of the carrying cost of $154 million will be recognized in income as collected.

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

We believe that our recorded net true-up regulatory asset of $1.6 billion at March 31, 2005 is recoverable under the Texas Restructuring Legislation; however, we anticipate that other parties will contend that material amounts of stranded costs should not be recovered. To the extent decisions of the PUCT in our future True-up Proceeding differ from our interpretation and application of the Texas Restructuring Legislation and our evaluation of other true-up orders of nonaffiliated companies, additional material disallowances and reductions of recorded carrying costs are possible, which could have a material adverse effect on our future results of operations, cash flows and possibly financial condition.

TCC Rate Case

We have an on-going transmission and distribution rate review before the PUCT. In that rate review, the PUCT has issued various decisions and conducted additional hearings in March 2005. At an open meeting on April 13, 2005, the PUCT decided all remaining issues except the amount of affiliate expenses to include in revenue requirements which the PUCT decided to defer. Adjusted for the decisions approved by the PUCT through April 13, 2005, the ALJ's recommended disallowances of affiliate expenses would produce an annual rate reduction of $25 million to $52 million. If we were to prevail on the affiliate expenses issue, the result would be an annual rate increase of $2 million. An order reducing our rates could have an adverse effect on future results of operations and cash flows.

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

Critical Accounting Estimates

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

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

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

MTM Risk Management Contract Net Assets

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

MTM Risk Management Contract Net Assets
Three Months Ended March 31, 2005
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2004	$	9,701
(Gain) Loss from Contracts Realized/Settled During the Period (a)		(3,113)
Fair Value of New Contracts When Entered During the Period (b)		33
Net Option Premiums Paid/(Received) (c)		-
Change in Fair Value Due to Valuation Methodology Changes		-
Changes in Fair Value of Risk Management Contracts (d)		(3,799)
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (e)		-
Total MTM Risk Management Contract Net Assets		2,822
Net Cash Flow Hedge Contracts (f)		(4,221)
Total MTM Risk Management Contract Net Assets (Liabilities) at March 31, 2005	$	(1,399)

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

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

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

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

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

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

Reconciliation of MTM Risk Management Contracts to Consolidated Balance Sheets
As of March 31, 2005
(in thousands)

	MTM Risk Management Contracts (a)	Cash Flow Hedges	Total (b)
Current Assets	$ 4,951	$ 2,116	$ 7,067
Noncurrent Assets	4,275	46	4,321
Total MTM Derivative Contract Assets	9,226	2,162	11,388
Current Liabilities	(4,394)	(6,269)	(10,663)
Noncurrent Liabilities	(2,010)	(114)	(2,124)
Total MTM Derivative Contract Liabilities	(6,404)	(6,383)	(12,787)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 2,822	$ (4,221)	$ (1,399)

(a) Does not include Cash Flow Hedges.
(b) Represents amount of total MTM derivative contracts recorded within Risk Management Assets, Long-term Risk Management Assets, Risk Management Liabilities and Long-term Risk Management Liabilities on our Consolidated Balance Sheets.

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

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

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

Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets
Fair Value of Contracts as of March 31, 2005
(in thousands)

	Remainder of 2005	2006	2007	2008	2009	After 2009	Total (c)
Prices Actively Quoted – Exchange Traded Contracts	$ (609)	$ 234	$ 485	$ -	$ -	$ -	$ 110
Prices Provided by Other External Sources - OTC Broker Quotes (a)	1,185	1,006	740	317	-	-	3,248
Prices Based on Models and Other Valuation Methods (b)	14	(855)	(713)	173	381	464	(536)
Total	$ 590	$ 385	$ 512	$ 490	$ 381	$ 464	$ 2,822

(a) "Prices Provided by Other External Sources – OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.
(b) "Prices Based on Models and Other Valuation Methods" is in absence of pricing information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations

are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.
(c) Amounts exclude Cash Flow Hedges.

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

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

The table provides detail on effective cash flow hedges under SFAS 133 included in the Consolidated Balance Sheets. The data in the table indicates the magnitude of SFAS 133 hedges we have in place. Under SFAS 133, only contracts designated as cash flow hedges are recorded in AOCI, therefore, economic hedge contracts which are not designated as cash flow hedges are required to be marked-to-market and are included in the previous risk management tables. In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Three Months Ended March 31, 2005
(in thousands)

	Power
Beginning Balance December 31, 2004	$ 657
Changes in Fair Value (a)	(4,094)
Reclassifications from AOCI to Net Income (b)	(242)
Ending Balance March 31, 2005	$ (3,679)

(a) "Changes in Fair Value" shows changes in the fair value of derivatives designated as cash flow hedges during the reporting period that are not yet settled at March 31, 2005. Amounts are reported net of related income taxes.
(b) "Reclassifications from AOCI to Net Income" represents gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into net income during the reporting period. Amounts are reported net of related income taxes.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $3,634 thousand loss.

Credit Risk

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

VaR Associated with Management Contracts

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

Three Months Ended March 31, 2005 (in thousands)				Twelve Months Ended December 31, 2004 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$40	$88	$43	$26	$157	$511	$220	$75

VaR Associated with Debt Outstanding

The risk of potential loss in fair value attributable to our exposure to interest rates, primarily related to long-term debt with fixed interest rates, was $127 million and $120 million at March 31, 2005 and December 31, 2004, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period. Therefore, a near term change in interest rates should not negatively affect our results of operation or consolidated financial position.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2005 and 2004
(Unaudited)
(in thousands)

	2005	2004
OPERATING REVENUES		
Electric Generation, Transmission and Distribution	$ 182,194	$ 268,858
Sales to AEP Affiliates	4,964	18,130
TOTAL	187,158	286,988
OPERATING EXPENSES		
Fuel for Electric Generation	6,075	23,106
Fuel from Affiliates for Electric Generation	23	40,199
Purchased Electricity for Resale	15,370	10,086
Purchased Electricity from AEP Affiliates	-	4,073
Other Operation	65,660	75,441
Maintenance	17,039	15,404
Depreciation and Amortization	29,286	29,097
Taxes Other Than Income Taxes	22,531	22,057
Income Taxes	1,461	12,006
TOTAL	157,445	231,469
OPERATING INCOME	29,713	55,519
Nonoperating Income	11,155	12,102
Nonoperating Expenses	15,137	5,108
Nonoperating Income Tax Credit	2,485	20
Interest Charges	27,079	33,129
NET INCOME	1,137	29,404
Preferred Stock Dividend Requirements	60	60
EARNINGS APPLICABLE TO COMMON STOCK	$ 1,077	$ 29,344

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

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2005 and 2004
(Unaudited)
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2003	$ 55,292	$ 132,606	$ 1,083,023	$ (61,872)	$ 1,209,049
Common Stock Dividends			(24,000)		(24,000)
Preferred Stock Dividends			(60)		(60)
TOTAL					1,184,989
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $7,411				(13,763)	(13,763)
Minimum Pension Liability, Net of Tax of $0				(2,466)	(2,466)
NET INCOME			29,404		29,404
TOTAL COMPREHENSIVE INCOME					13,175
MARCH 31, 2004	$ 55,292	$ 132,606	$ 1,088,367	$ (78,101)	$ 1,198,164
DECEMBER 31, 2004	$ 55,292	$ 132,606	$ 1,084,904	$ (4,159)	$ 1,268,643
Preferred Stock Dividends			(60)		(60)
TOTAL					1,268,583
COMPREHENSIVE INCOME (LOSS)					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $2,335				(4,336)	(4,336)
NET INCOME			1,137		1,137
TOTAL COMPREHENSIVE LOSS					(3,199)
MARCH 31, 2005	$ 55,292	$ 132,606	$ 1,085,981	$ (8,495)	$ 1,265,384

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

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

	2005	2004
ELECTRIC UTILITY PLANT		
Transmission	$ 791,529	$ 788,371
Distribution	1,443,548	1,433,380
General	219,463	220,435
Construction Work in Progress	53,481	50,612
Total	2,508,021	2,492,798
Accumulated Depreciation and Amortization	729,655	725,225
TOTAL - NET	1,778,366	1,767,573
OTHER PROPERTY AND INVESTMENTS		
Nonutility Property, Net	2,360	1,577
Bond Defeasance Funds	21,642	22,110
TOTAL	24,002	23,687
CURRENT ASSETS		
Cash and Cash Equivalents	973	-
Other Cash Deposits	103,601	135,132
Accounts Receivable:		
Customers	156,320	157,431
Affiliated Companies	12,168	67,860
Accrued Unbilled Revenues	23,327	21,589
Allowance for Uncollectible Accounts	(688)	(3,493)
Materials and Supplies	12,240	12,288
Risk Management Assets	7,067	14,048
Margin Deposits	2,778	1,891
Prepayments and Other Current Assets	15,464	9,151
TOTAL	333,250	415,897
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	18,562	15,236
Wholesale Capacity Auction True-Up	574,027	559,973
Unamortized Loss on Reacquired Debt	11,576	11,842
Designated for Securitization	1,345,935	1,361,299
Deferred Debt – Restructuring	11,368	11,596
Other	95,921	102,032
Securitized Transition Assets	632,000	642,384
Long-term Risk Management Assets	4,321	9,508
Prepaid Pension Obligations	109,995	109,628
Deferred Property Taxes	29,820	-
Deferred Charges	33,951	36,986
TOTAL	2,867,476	2,860,484
Assets Held for Sale – Texas Generation Plants	635,776	628,149
TOTAL ASSETS	$ 5,638,870	$ 5,695,790

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

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

	2005	2004
CAPITALIZATION	(in thousands)	
Common Shareholder's Equity:		
Common Stock - $25 par value per share:		
Authorized – 12,000,000 shares		
Outstanding – 2,211,678 shares	$ 55,292	$ 55,292
Paid-in Capital	132,606	132,606
Retained Earnings	1,085,981	1,084,904
Accumulated Other Comprehensive Income (Loss)	(8,495)	(4,159)
Total Common Shareholder's Equity	1,265,384	1,268,643
Cumulative Preferred Stock Not Subject to Mandatory Redemption	5,940	5,940
Total Shareholders' Equity	1,271,324	1,274,583
Long-term Debt - Nonaffiliated	1,672,695	1,541,552
TOTAL	2,944,019	2,816,135
CURRENT LIABILITIES		
Long-term Debt Due Within One Year - Nonaffiliated	116,997	365,742
Advances from Affiliates	238,693	207
Accounts Payable:		
General	64,384	109,688
Affiliated Companies	68,003	64,045
Customer Deposits	4,974	6,147
Taxes Accrued	66,229	184,014
Interest Accrued	19,589	41,227
Risk Management Liabilities	10,663	8,394
Obligations Under Capital Leases	431	412
Other	17,511	20,115
TOTAL	607,474	799,991
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	1,253,495	1,247,111
Long-term Risk Management Liabilities	2,124	4,896
Regulatory Liabilities:		
Asset Removal Costs	103,419	102,624
Deferred Investment Tax Credits	106,677	107,743
Over-recovery of Fuel Costs	214,426	211,526
Retail Clawback	61,384	61,384
Other	74,318	76,653
Obligations Under Capital Leases	498	468
Deferred Credits and Other	16,525	17,276
TOTAL	1,832,866	1,829,681
Liabilities Held for Sale – Texas Generation Plants	254,511	249,983
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$ 5,638,870	$ 5,695,790

See Notes to Financial Statements of Registrant Subsidiaries beginning on page L-1.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2005 and 2004
(Unaudited)
(in thousands)

	2005	2004
OPERATING ACTIVITIES		
Net Income	$ 1,137	$ 29,404
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Depreciation and Amortization	29,286	29,097
Accretion Expense	4,529	4,067
Deferred Income Taxes	(5,045)	(3,401)
Deferred Investment Tax Credits	(1,066)	(1,302)
Deferred Property Taxes	(29,820)	(33,660)
Pension and Postemployment Benefit Reserves	(1,072)	259
Mark-to-Market of Risk Management Contracts	6,879	5,035
Pension Contributions	(57)	-
Carrying Costs	5,141	-
Wholesale Capacity Auction True-up	769	-
Over/Under Fuel Recovery	2,900	13,000
(Gain)/Loss on Sale of Assets	(48)	(49)
Change in Other Noncurrent Assets	(7,731)	1,439
Change in Other Noncurrent Liabilities	6,929	(11,037)
Changes in Components of Working Capital:		
Accounts Receivable, Net	52,260	937
Fuel, Materials and Supplies	98	499
Accounts Payable	(41,346)	(14,259)
Taxes Accrued	(117,785)	31,652
Customer Deposits	(1,173)	1,974
Interest Accrued	(21,638)	(19,948)
Other Current Assets	(1,879)	(2,527)
Other Current Liabilities	(2,584)	(5,307)
Net Cash Flows From (Used For) Operating Activities	(121,316)	25,873
INVESTING ACTIVITIES		
Construction Expenditures	(27,534)	(23,748)
Change in Other Cash Deposits, Net	31,531	28,330
Net Cash Flows From Investing Activities	3,997	4,582
FINANCING ACTIVITIES		
Issuance of Long-term Debt	159,252	-
Retirement of Long-term Debt	(279,386)	(29,864)
Changes in Advances to/from Affiliates, Net	238,486	24,742
Dividends Paid on Common Stock	-	(24,000)
Dividends Paid on Cumulative Preferred Stock	(60)	(60)
Net Cash Flows From (Used For) Financing Activities	118,292	(29,182)
Net Increase in Cash and Cash Equivalents	973	1,273
Cash and Cash Equivalents at Beginning of Period	-	760
Cash and Cash Equivalents at End of Period	$ 973	$ 2,033

SUPPLEMENTAL DISCLOSURE:
Cash paid (received) for interest net of capitalized amounts was $44,721,000 and $49,928,000 and for income taxes was $132,960,000 and $(7,567,000) in 2005 and 2004, respectively. Noncash capital lease acquisitions were $157,000 and $69,000 in 2005 and 2004, respectively.

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

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

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

AEP TEXAS NORTH COMPANY

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

Results of Operations

First Quarter of 2005 Compared to First Quarter of 2004

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

First Quarter of 2004 Net Income		$ 13
Changes in Gross Margin:		
Texas Supply	(3)	
Off-system Sales	(2)	
Other Revenues	(4)	
Total Change in Gross Margin		(9)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	2	
Taxes Other Than Income Taxes	(1)	
Nonoperating Income and Expenses, Net	(2)	
Interest Charges	1	
Total Change in Operating Expenses and Other		-
Income Tax Expense		3
First Quarter of 2005 Net Income		$ 7

Net Income decreased $6 million to $7 million in the first quarter of 2005. The key drivers of the decrease were a $9 million decrease in gross margin offset by a $3 million decrease in Income Tax Expense.

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

- Texas Supply margins decreased by $3 million primarily due to the loss of ERCOT reliability-must-run (RMR) revenue of $2 million.
- Margins from Off-system Sales for 2005 decreased by $2 million in comparison to 2004 primarily due to lower optimization activity.
- Other Revenues margins decreased $4 million primarily due to a prior year unfavorable adjustment for affiliated OATT and ancillary services resulting from revised ERCOT data received for the years 2001 through 2003.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses decreased $2 million primarily due to decreased production plant operations and related maintenance for RMR plants no longer in use offset in part by increased transmission cost related to ERCOT.
- Taxes Other Than Income Taxes increased $1 million primarily due to property related taxes offset in part by lower state and local franchise tax expense.
- Nonoperating Income and Expenses, Net decreased $2 million primarily due to the absence of risk management activities in the first quarter of 2005.
- Interest Charges decreased $1 million primarily due to long-term debt maturities in 2004 and interest in 2004 related to the FERC settlement with wholesale customers.

Income Taxes

The effective tax rate for the first quarter of 2005 and 2004 was 33.8% and 34.3%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to permanent differences, amortization of investment tax credits and state income taxes. The effective tax rate remained relatively flat for the comparative period.

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	A3	BBB	A
Senior Unsecured Debt	Baa1	BBB	A-

Financing Activity

There were no long-term debt issuances or retirements during the first three months of 2005.

Significant Factors

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

Critical Accounting Estimates

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

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

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

MTM Risk Management Contract Net Assets

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

MTM Risk Management Contract Net Assets
Three Months Ended March 31, 2005
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2004	$	4,192
(Gain) Loss from Contracts Realized/Settled During the Period (a)		(1,345)
Fair Value of New Contracts When Entered During the Period (b)		14
Net Option Premiums Paid/(Received) (c)		-
Change in Fair Value Due to Valuation Methodology Changes		-
Changes in Fair Value of Risk Management Contracts (d)		(1,642)
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (e)		-
Total MTM Risk Management Contract Net Assets		1,219
Net Cash Flow Hedge Contracts (f)		1,006
Total MTM Risk Management Contract Net Assets at March 31, 2005	$	2,225

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

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

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

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

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

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

Reconciliation of MTM Risk Management Contracts to Balance Sheets
As of March 31, 2005
(in thousands)

	MTM Risk Management Contracts (a)	Cash Flow Hedges	Total (b)
Current Assets	$ 2,140	$ 2,390	$ 4,530
Noncurrent Assets	1,848	20	1,868
Total MTM Derivative Contract Assets	3,988	2,410	6,398
Current Liabilities	(1,900)	(1,355)	(3,255)
Noncurrent Liabilities	(869)	(49)	(918)
Total MTM Derivative Contract Liabilities	(2,769)	(1,404)	(4,173)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 1,219	$ 1,006	$ 2,225

(a) Does not include Cash Flow Hedges.
(b) Represents amount of total MTM derivative contracts recorded within Risk Management Assets, Long-term Risk Management Assets, Risk Management Liabilities and Long-term Risk Management Liabilities on our Balance Sheets.

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

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

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

Maturity and Source of Fair Value of MTM
Risk Management Contract Net Assets
Fair Value of Contracts as of March 31, 2005
(in thousands)

	Remainder of 2005	2006	2007	2008	2009	After 2009	Total (c)
Prices Actively Quoted – Exchange Traded Contracts	$ (263)	$ 101	$ 210	$ -	$ -	$ -	$ 48
Prices Provided by Other External Sources - OTC Broker Quotes (a)	512	435	320	137	-	-	1,404
Prices Based on Models and Other Valuation Methods (b)	4	(370)	(308)	75	165	201	(233)
Total	$ 253	$ 166	$ 222	$ 212	$ 165	$ 201	$ 1,219

(a) "Prices Provided by Other External Sources – OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.
(b) "Prices Based on Models and Other Valuation Methods" is in absence of pricing information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such

valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.

(c) Amounts exclude Cash Flow Hedges.

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

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

The table provides detail on effective cash flow hedges under SFAS 133 included in the Balance Sheets. The data in the table indicates the magnitude of SFAS 133 hedges we have in place. Under SFAS 133, only contracts designated as cash flow hedges are recorded in AOCI, therefore, economic hedge contracts which are not designated as cash flow hedges are required to be marked-to-market and are included in the previous risk management tables. In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Three Months Ended March 31, 2005
(in thousands)

	Power
Beginning Balance December 31, 2004	$ 285
Changes in Fair Value (a)	(670)
Reclassifications from AOCI to Net Income (b)	(104)
Ending Balance March 31, 2005	$ (489)

(a) "Changes in Fair Value" shows changes in the fair value of derivatives designated as cash flow hedges during the reporting period that are not yet settled at March 31, 2005. Amounts are reported net of related income taxes.

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

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $470 thousand loss.

Credit Risk

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

VaR Associated with Risk Management Contracts

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

Three Months Ended March 31, 2005 (in thousands)				Twelve Months Ended December 31, 2004 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$17	$38	$19	$11	$68	$221	$95	$33

VaR Associated with Debt Outstanding

The risk of potential loss in fair value attributable to our exposure to interest rates, primarily related to long-term debt with fixed interest rates, was $15 million and $13 million at March 31, 2005 and December 31, 2004, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period. Therefore, a near term change in interest rates should not negatively affect our results of operation or financial position.