Fair Value Measurements of Assets and Liabilities

The accounting guidance for "Fair Value Measurements and Disclosures" establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. When quoted market prices are not available, pricing may be completed using comparable securities, dealer values, operating data and general market conditions to determine fair value. Valuation models utilize various inputs such as commodity, interest rate and, to a lesser degree, volatility and credit that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability.

For our commercial activities, exchange traded derivatives, namely futures contracts, are generally fair valued based on unadjusted quoted prices in active markets and are classified as Level 1. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, as well as exchange traded contracts where there is insufficient market liquidity to warrant inclusion in Level 1. We verify our price curves using these broker quotes and classify these fair values within Level 2 when substantially all of the fair value can be corroborated. We typically obtain multiple broker quotes, which are non-binding in nature, but are based on recent trades in the marketplace. When multiple broker quotes are obtained, we average the quoted bid and ask prices. In certain circumstances, we may discard a broker quote if it is a clear outlier. We use a historical correlation analysis between the broker quoted location and the illiquid locations and if the points are highly correlated we include these locations within Level 2 as well. Certain OTC and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. Long-dated and illiquid complex or structured transactions and FTRs can introduce the need for internally developed modeling inputs based upon extrapolations and assumptions of observable market data to estimate fair value. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized as Level 3.

We utilize our trustee's external pricing service in our estimate of the fair value of the underlying investments held in the benefit plan and nuclear trusts. Our investment managers review and validate the prices utilized by the trustee to determine fair value. We perform our own valuation testing to verify the fair values of the securities. We receive audit reports of our trustee's operating controls and valuation processes. The trustee uses multiple pricing vendors for the assets held in the trusts.

Assets in the benefits and nuclear trusts, Cash and Cash Equivalents and Other Temporary Investments are classified using the following methods. Equities are classified as Level 1 holdings if they are actively traded on exchanges. Items classified as Level 1 are investments in money market funds, fixed income and equity mutual funds and domestic equity securities. They are valued based on observable inputs primarily unadjusted quoted prices in active markets for identical assets. Items classified as Level 2 are primarily investments in individual fixed income securities and cash equivalents funds. Fixed income securities do not trade on an exchange and do not have an official closing price but their valuation inputs are based on observable market data. Pricing vendors calculate bond valuations using financial models and matrices. The models use observable inputs including yields on benchmark securities, quotes by securities brokers, rating agency actions, discounts or premiums on securities compared to par prices, changes in yields for U.S. Treasury securities, corporate actions by bond issuers, prepayment schedules and histories, economic events and, for certain securities, adjustments to yields to reflect changes in the rate of inflation. Other securities with model-derived valuation inputs that are observable are also classified as Level 2 investments. Investments with unobservable valuation inputs are classified as Level 3 investments. Benefit plan assets included in Level 3 are primarily real estate and private equity investments that are valued using methods requiring judgment including appraisals.

Deferred Fuel Costs

The cost of fuel and related emission allowances and emission control chemicals/consumables is charged to Fuel and Other Consumables Used for Electric Generation expense when the fuel is burned or the allowance or consumable is utilized. The cost of fuel also includes the cost of nuclear fuel burned which is computed primarily on the units-of-production method. In regulated jurisdictions with an active FAC, fuel cost over-recoveries (the excess of fuel revenues billed to customers over applicable fuel costs incurred) are generally deferred as current regulatory liabilities and under-recoveries (the excess of applicable fuel costs incurred over fuel revenues billed to customers) are generally deferred as current regulatory assets. These deferrals are amortized when refunded or when billed to customers in later months with the state regulatory commissions' review and approval. The amount of an over-recovery or under-recovery can also be affected by actions of the state regulatory commissions. On a routine basis, state regulatory commissions review and/or audit our fuel procurement policies and practices, the fuel cost calculations and FAC deferrals. When a fuel cost disallowance becomes probable, we adjust our FAC deferrals and record provisions for estimated refunds to recognize these probable outcomes. Fuel cost over-recovery and under-recovery balances are classified as noncurrent when there is a phase-in plan or the FAC has been suspended or terminated.

Changes in fuel costs, including purchased power in Kentucky for KPCo, in Indiana and Michigan for I&M, in Ohio (beginning in 2012 through May 2015) for OPCo, in Arkansas, Louisiana and Texas for SWEPCo, in Oklahoma for PSO and in Virginia for APCo are reflected in rates in a timely manner through the FAC. Changes in fuel costs, including purchased power in Ohio (beginning in 2009 through 2011) for OPCo and in West Virginia for APCo are reflected in rates through FAC phase-in plans. The FAC generally includes some sharing of off-system sales. In West Virginia for APCo, all of the profits from off-system sales are given to customers through the FAC. None of the profits from off-system sales are given to customers through the FAC in Ohio for OPCo. A portion of profits from off-system sales are given to customers through the FAC and other rate mechanisms in Oklahoma for PSO, Arkansas, Louisiana and Texas for SWEPCo, Kentucky for KPCo, Virginia for APCo and in Indiana and Michigan (all areas of Michigan beginning in December 2010) for I&M. Where the FAC or off-system sales sharing mechanism is capped, frozen or non-existent, changes in fuel costs or sharing of off-system sales impacted earnings.

Revenue Recognition

Regulatory Accounting

Our financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated. Regulatory assets (deferred expenses) and regulatory liabilities (deferred revenue reductions or refunds) are recorded to reflect the economic effects of regulation in the same accounting period by matching expenses with their recovery through regulated revenues and by matching income with its passage to customers in cost-based regulated rates.

When regulatory assets are probable of recovery through regulated rates, we record them as assets on our balance sheets. We test for probability of recovery at each balance sheet date or whenever new events occur. Examples of new events include the issuance of a regulatory commission order or passage of new legislation. If it is determined that recovery of a regulatory asset is no longer probable, we write off that regulatory asset as a charge against income.

Traditional Electricity Supply and Delivery Activities

Revenues are recognized from retail and wholesale electricity sales and electricity transmission and distribution delivery services. We recognize the revenues on our statements of income upon delivery of the energy to the customer and include unbilled as well as billed amounts. In accordance with the applicable state commission regulatory treatment, PSO and SWEPCo do not record the fuel portion of unbilled revenue.

Most of the power produced at the generation plants of the AEP East companies is sold to PJM, the RTO operating in the east service territory. We purchase power from PJM to supply our customers. Generally, these power sales and purchases are reported on a net basis as revenues on our statements of income. However, purchases of power in excess of sales to PJM, on an hourly net basis, used to serve retail load are recorded gross as Purchased Electricity for Resale on our statements of income. Other RTOs in which we participate do not function in the same manner as PJM. They function as balancing organizations and not as exchanges.

Physical energy purchases arising from non-derivative contracts are accounted for on a gross basis in Purchased Electricity for Resale on our statements of income. Energy purchases arising from non-trading derivative contracts are recorded based on the transaction's economic substance. Purchases under non-trading derivatives used to serve accrual based obligations are recorded in Purchased Electricity for Resale on our statements of income. All other non-trading derivative purchases are recorded net in revenues.

In general, we record expenses when purchased electricity is received and when expenses are incurred, with the exception of certain power purchase contracts that are derivatives and accounted for using MTM accounting where generation/supply rates are not cost-based regulated. In jurisdictions where the generation/supply business is subject to cost-based regulation, the unrealized MTM amounts are deferred as regulatory assets (for losses) and regulatory liabilities (for gains).

Energy Marketing and Risk Management Activities

We engage in wholesale electricity, natural gas, coal and emission allowances marketing and risk management activities focused on wholesale markets where we own assets and adjacent markets. Our activities include the purchase and sale of energy under forward contracts at fixed and variable prices and the buying and selling of financial energy contracts, which include exchange traded futures and options, as well as OTC options and swaps. We engage in certain energy marketing and risk management transactions with RTOs.

We recognize revenues and expenses from wholesale marketing and risk management transactions that are not derivatives upon delivery of the commodity. We use MTM accounting for wholesale marketing and risk management transactions that are derivatives unless the derivative is designated in a qualifying cash flow hedge relationship or a normal purchase or sale. We include the unrealized and realized gains and losses on wholesale marketing and risk management transactions that are accounted for using MTM in Revenues on our statements of income on a net basis. In jurisdictions subject to cost-based regulation, we defer the unrealized MTM amounts and some realized gains and losses as regulatory assets (for losses) and regulatory liabilities (for gains). We include unrealized MTM gains and losses resulting from derivative contracts on our balance sheets as Risk Management Assets or Liabilities as appropriate.

Certain qualifying wholesale marketing and risk management derivative transactions are designated as hedges of variability in future cash flows as a result of forecasted transactions (cash flow hedge). We initially record the effective portion of the cash flow hedge's gain or loss as a component of AOCI. When the forecasted transaction is realized and affects net income, we subsequently reclassify the gain or loss on the hedge from AOCI into revenues or expenses within the same financial statement line item as the forecasted transaction on our statements of income. Excluding those jurisdictions subject to cost-based regulation, we recognize the ineffective portion of the gain or loss in revenues or expense immediately on our statements of income, depending on the specific nature of the associated hedged risk. In regulated jurisdictions, we defer the ineffective portion as regulatory assets (for losses) and regulatory liabilities (for gains). See "Accounting for Cash Flow Hedging Strategies" section of Note 9.

Barging Activities

AEP River Operations' revenue is recognized based on percentage of voyage completion. The proportion of freight transportation revenue to be recognized is determined by applying a percentage to the contractual charges for such services. The percentage is determined by dividing the number of miles from the loading point to the position of the barge as of the end of the accounting period by the total miles to the destination specified in the customer's freight contract. The position of the barge at accounting period end is determined by our computerized barge tracking system.

Levelization of Nuclear Refueling Outage Costs

In accordance with regulatory orders, I&M defers incremental operation and maintenance costs associated with periodic refueling outages at its Cook Plant and amortizes the costs over the period beginning with the month following the start of each unit's refueling outage and lasting until the end of the month in which the same unit's next scheduled refueling outage begins. I&M adjusts the amortization amount as necessary to ensure full amortization of all deferred costs by the end of the refueling cycle.

Maintenance

We expense maintenance costs as incurred. If it becomes probable that we will recover specifically-incurred costs through future rates, we establish a regulatory asset to match the expensing of those maintenance costs with their recovery in cost-based regulated revenues. In certain regulatory jurisdictions, we defer costs above the level included in base rates and amortize those deferrals commensurate with recovery through rate riders.

Income Taxes and Investment Tax Credits

We use the liability method of accounting for income taxes. Under the liability method, we provide deferred income taxes for all temporary differences between the book and tax basis of assets and liabilities which will result in a future tax consequence.

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

We account for investment tax credits under the flow-through method except where regulatory commissions reflect investment tax credits in the rate-making process on a deferral basis. We amortize deferred investment tax credits over the life of the plant investment.

We account for uncertain tax positions in accordance with the accounting guidance for "Income Taxes." We classify interest expense or income related to uncertain tax positions as interest expense or income as appropriate and classify penalties as Other Operation.

Excise Taxes

We act as an agent for some state and local governments and collect from customers certain excise taxes levied by those state or local governments on our customers. We do not recognize these taxes as revenue or expense.

Government Grants

For APCo's commercial scale Carbon Capture and Sequestration facility at the Mountaineer Plant and OPCo's gridSMART® demonstration program, APCo and OPCo are reimbursed by the Department of Energy for allowable costs incurred during the billing period. These reimbursements result in the reduction of Other Operation and Maintenance expenses on our statements of income or a reduction in Construction Work in Progress on our balance sheets.

Debt

We defer gains and losses from the reacquisition of debt used to finance regulated electric utility plants and amortize the deferral over the remaining term of the reacquired debt in accordance with their rate-making treatment unless the debt is refinanced. If we refinance the reacquired debt associated with the regulated business, the reacquisition costs attributable to the portions of the business subject to cost-based regulatory accounting are generally deferred and amortized over the term of the replacement debt consistent with its recovery in rates. Some jurisdictions require that these costs be expensed upon reacquisition. We report gains and losses on the reacquisition of debt for operations not subject to cost-based rate regulation in Interest Expense on our statements of income.

We defer debt discount or premium and debt issuance expenses and amortize generally utilizing the straight-line method over the term of the related debt. The straight-line method approximates the effective interest method and is consistent with the treatment in rates for regulated operations. We include the net amortization expense in Interest Expense on our statements of income.

Goodwill and Intangible Assets

When we acquire businesses, we record the fair value of all assets and liabilities, including intangible assets. To the extent that consideration exceeds the fair value of identified assets, we record goodwill. We do not amortize goodwill and intangible assets with indefinite lives. We test acquired goodwill and other intangible assets with indefinite lives for impairment at least annually at their estimated fair value. We test goodwill at the reporting unit level and other intangibles at the asset level. Fair value is the amount at which an asset or liability could be bought or sold in a current transaction between willing parties, that is, other than in a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, we estimate fair value using various internal and external valuation methods. We amortize intangible assets with finite lives over their respective estimated lives to their estimated residual values. We also review the lives of the amortizable intangibles with finite lives on an annual basis.

Investments Held in Trust for Future Liabilities

We have several trust funds with significant investments intended to provide for future payments of pension and OPEB benefits, nuclear decommissioning and spent nuclear fuel disposal. All of our trust funds' investments are diversified and managed in compliance with all laws and regulations. Our investment strategy for trust funds is to use a diversified portfolio of investments to achieve an acceptable rate of return while managing the interest rate sensitivity of the assets relative to the associated liabilities. To minimize investment risk, the trust funds are broadly diversified among classes of assets, investment strategies and investment managers. We regularly review the actual asset allocations and periodically rebalance the investments to targeted allocations when appropriate. Investment policies and guidelines allow investment managers in approved strategies to use financial derivatives to obtain or manage market exposures and to hedge assets and liabilities. The investments are reported at fair value under the "Fair Value Measurements and Disclosures" accounting guidance.

Benefit Plans

All benefit plan assets are invested in accordance with each plan's investment policy. The investment policy outlines the investment objectives, strategies and target asset allocations by plan.

The investment philosophies for our benefit plans support the allocation of assets to minimize risks and optimize net returns. Strategies used include:

- Maintaining a long-term investment horizon.
- Diversifying assets to help control volatility of returns at acceptable levels.
- Managing fees, transaction costs and tax liabilities to maximize investment earnings.
- Using active management of investments where appropriate risk/return opportunities exist.
- Keeping portfolio structure style-neutral to limit volatility compared to applicable benchmarks.
- Using alternative asset classes such as real estate and private equity to maximize return and provide additional portfolio diversification.

The investment policy for the pension fund allocates assets based on the funded status of the pension plan. The objective of the asset allocation policy is to reduce the investment volatility of the plan over time. Generally, more of the investment mix will be allocated to fixed income investments as the plan becomes better funded. Assets will be transferred away from equity investments into fixed income investments based on the market value of plan assets compared to the plan's projected benefit obligation. The current target asset allocations are as follows:

Pension Plan Assets	Target
Equity	45.0 %
Fixed Income	45.0 %
Other Investments	10.0 %

OPEB Plans Assets	Target
Equity	66.0 %
Fixed Income	33.0 %
Cash	1.0 %

The investment policy for each benefit plan contains various investment limitations. The investment policies establish concentration limits for securities. Investment policies prohibit the benefit trust funds from purchasing securities issued by AEP (with the exception of proportionate and immaterial holdings of AEP securities in passive index strategies). However, our investment policies do not preclude the benefit trust funds from receiving contributions in the form of AEP securities, provided that the AEP securities acquired by each plan may not exceed the limitations imposed by law. Each investment manager's portfolio is compared to a diversified benchmark index.

For equity investments, the limits are as follows:

- No security in excess of 5% of all equities.
- Cash equivalents must be less than 10% of an investment manager's equity portfolio.
- No individual stock may be more than 10% of each manager's equity portfolio.
- No investment in excess of 5% of an outstanding class of any company.
- No securities may be bought or sold on margin or other use of leverage.

For fixed income investments, the concentration limits must not exceed:

- 3% in any single issuer
- 5% private placements
- 5% convertible securities
- 60% for bonds rated AA+ or lower
- 50% for bonds rated A+ or lower
- 10% for bonds rated BBB- or lower

For obligations of non-government issuers, the following limitations apply:

- AAA rated debt: a single issuer should account for no more than 5% of the portfolio.
- AA+, AA, AA- rated debt: a single issuer should account for no more than 3% of the portfolio.
- Debt rated A+ or lower: a single issuer should account for no more than 2% of the portfolio.
- No more than 10% of the portfolio may be invested in high yield and emerging market debt combined at any time.

A portion of the pension assets is invested in real estate funds to provide diversification, add return and hedge against inflation. Real estate properties are illiquid, difficult to value and not actively traded. The pension plan uses external real estate investment managers to invest in commingled funds that hold real estate properties. To mitigate investment risk in the real estate portfolio, commingled real estate funds are used to ensure that holdings are diversified by region, property type and risk classification. Real estate holdings include core, value-added and development risk classifications and some investments in Real Estate Investment Trusts (REITs), which are publicly traded real estate securities classified as Level 1.

A portion of the pension assets is invested in private equity. Private equity investments add return and provide diversification and typically require a long-term time horizon to evaluate investment performance. Private equity is classified as an alternative investment because it is illiquid, difficult to value and not actively traded. The pension plan uses limited partnerships and commingled funds to invest across the private equity investment spectrum. Our private equity holdings are with 11 general partners who help monitor the investments and provide investment selection expertise. The holdings are currently comprised of venture capital, buyout and hybrid debt and equity investment instruments. Commingled private equity funds are used to enhance the holdings' diversity.

We participate in a securities lending program with BNY Mellon to provide incremental income on idle assets and to provide income to offset custody fees and other administrative expenses. We lend securities to borrowers approved by BNY Mellon in exchange for cash collateral. All loans are collateralized by at least 102% of the loaned asset's market value and the cash collateral is invested. The difference between the rebate owed to the borrower and the cash collateral rate of return determines the earnings on the loaned security. The securities lending program's objective is providing modest incremental income with a limited increase in risk.

We hold trust owned life insurance (TOLI) underwritten by The Prudential Insurance Company in the OPEB plan trusts. The strategy for holding life insurance contracts in the taxable Voluntary Employees' Beneficiary Association (VEBA) trust is to minimize taxes paid on the asset growth in the trust. Earnings on plan assets are tax-deferred within the TOLI contract and can be tax-free if held until claims are paid. Life insurance proceeds remain in the trust and are used to fund future retiree medical benefit liabilities. With consideration to other investments held in the trust, the cash value of the TOLI contracts is invested in two diversified funds. A portion is invested in a commingled fund with underlying investments in stocks that are actively traded on major international equity exchanges. The other portion of the TOLI cash value is invested in a diversified, commingled fixed income fund with underlying investments in government bonds, corporate bonds and asset-backed securities.

Cash and cash equivalents are held in each trust to provide liquidity and meet short-term cash needs. Cash equivalent funds are used to provide diversification and preserve principal. The underlying holdings in the cash funds are investment grade money market instruments including commercial paper, certificates of deposit, treasury bills and other types of investment grade short-term debt securities. The cash funds are valued each business day and provide daily liquidity.

Nuclear Trust Funds

Nuclear decommissioning and spent nuclear fuel trust funds represent funds that regulatory commissions allow us to collect through rates to fund future decommissioning and spent nuclear fuel disposal liabilities. By rules or orders, the IURC, the MPSC and the FERC established investment limitations and general risk management guidelines. In general, limitations include:

- Acceptable investments (rated investment grade or above when purchased).
- Maximum percentage invested in a specific type of investment.
- Prohibition of investment in obligations of AEP or its affiliates.
- Withdrawals permitted only for payment of decommissioning costs and trust expenses.

We maintain trust records for each regulatory jurisdiction. The trust assets may not be used for another jurisdiction's liabilities. Regulatory approval is required to withdraw decommissioning funds. These funds are managed by external investment managers who must comply with the guidelines and rules of the applicable regulatory authorities. The trust assets are invested to optimize the net of tax earnings of the trust giving consideration to liquidity, risk, diversification and other prudent investment objectives.

We record securities held in these trust funds as Spent Nuclear Fuel and Decommissioning Trusts on our balance sheets. We record these securities at fair value. We classify securities in the trust funds as available-for-sale due to their long-term purpose. Other-than-temporary impairments for investments in both debt and equity securities are considered realized losses as a result of securities being managed by an external investment management firm. The external investment management firm makes specific investment decisions regarding the equity and debt investments held in these trusts and generally intends to sell debt securities in an unrealized loss position as part of a tax optimization strategy. Impairments reduce the cost basis of the securities which will affect any future unrealized gain or realized gain or loss due to the adjusted cost of investment. We record unrealized gains and other-than-temporary impairments from securities in these trust funds as adjustments to the regulatory liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the spent nuclear fuel disposal trust funds in accordance with their treatment in rates. Consequently, changes in fair value of trust assets do not affect earnings or AOCI. See the "Nuclear Contingencies" section of Note 5 for additional discussion of nuclear matters. See "Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal" section of Note 10 for disclosure of the fair value of assets within the trusts.

Comprehensive Income (Loss)

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

Accumulated Other Comprehensive Income (Loss) (AOCI)

AOCI is included on our balance sheets in our equity section. Our components of AOCI as of December 31, 2011 and 2010 are shown in the following table:

Components	December 31, 2011	December 31, 2010
	(in millions)	
Cash Flow Hedges, Net of Tax	$ (23)	$ 11
Securities Available for Sale, Net of Tax	2	4
Amortization of Pension and OPEB Deferred Costs, Net of Tax	81	57
Pension and OPEB Funded Status, Net of Tax	(530)	(453)
Total	$ (470)	$ (381)

Stock-Based Compensation Plans

At December 31, 2011, we had stock options, performance units, restricted shares and restricted stock units outstanding under The Amended and Restated American Electric Power System Long-Term Incentive Plan (LTIP). This plan was last approved by shareholders in April 2010.

We maintain a variety of tax qualified and nonqualified deferred compensation plans for employees and non-employee directors that include, among other options, an investment in or an investment return equivalent to that of AEP common stock. This includes career share accounts maintained under the American Electric Power System Stock Ownership Requirement Plan, which facilitates executives in meeting minimum stock ownership requirements assigned to them by the HR Committee of the Board of Directors. Career shares are derived from vested performance units granted to employees under the LTIP. Career shares are equal in value to shares of AEP common stock and do not become payable to executives until after their service ends. Dividends paid on career shares are reinvested as additional career shares.

We compensate our non-employee directors, in part, with stock units under the American Electric Power Company, Inc. Stock Unit Accumulation Plan for Non-Employee Directors. These stock units become payable in cash to directors after their service ends.

In January 2006, we adopted accounting guidance for "Compensation - Stock Compensation" which requires the measurement and recognition of compensation expense for all share-based payment awards made to employees and directors, including stock options, based on estimated fair values.

We recognize compensation expense for all share-based awards with service only vesting conditions granted on or after January 2006 using the straight-line single-option method. Stock-based compensation expense recognized on our statements of income for the years ended December 31, 2011, 2010 and 2009 is based on awards ultimately expected to vest. Therefore, stock-based compensation expense has been reduced to reflect estimated forfeitures. Accounting guidance for "Compensation - Stock Compensation" requires forfeitures to be estimated at the time of grant and revised, if necessary, in subsequent periods if actual forfeitures differ from those estimates.

For the years ended December 31, 2011, 2010 and 2009, compensation expense is included in Net Income for the performance units, career shares, restricted shares, restricted stock units and the non-employee director's stock units. See Note 15 for additional discussion.

Earnings Per Share (EPS)

Shown below are income statement amounts attributable to AEP common shareholders:

	Years Ended December 31,		
Amounts Attributable to AEP Common Shareholders	**2011**	**2010**	**2009**
		(in millions)	
Income Before Extraordinary Items	$ 1,568	$ 1,211	$ 1,362
Extraordinary Items, Net of Tax	373	-	(5)
Net Income	$ 1,941	$ 1,211	$ 1,357

Basic earnings per common share is calculated by dividing net earnings available to common shareholders by the weighted average number of common shares outstanding during the period. Diluted earnings per common share is calculated by adjusting the weighted average outstanding common shares, assuming conversion of all potentially dilutive stock options and awards.

The following table presents our basic and diluted EPS calculations included on our statements of income:

	Years Ended December 31,					
	2011		**2010**		**2009**	
	(in millions, except per share data)					
		$/share		**$/share**		**$/share**
Earnings Attributable to AEP Common Shareholders	$ 1,941		$ 1,211		$ 1,357	
Weighted Average Number of Basic Shares Outstanding	482.2	$ 4.02	479.4	$ 2.53	458.7	$ 2.96
Weighted Average Dilutive Effect of:						
Performance Share Units	-	-	0.1	-	0.3	-
Stock Options	0.1	-	-	-	-	-
Restricted Stock Units	0.2	-	0.1	-	-	-
Weighted Average Number of Diluted Shares Outstanding	482.5	$ 4.02	479.6	$ 2.53	459.0	$ 2.96

Options to purchase 136,250 and 452,216 shares of common stock were outstanding at December 31, 2010 and 2009, respectively, but were not included in the computation of diluted earnings per share attributable to AEP common shareholders. Since the options' exercise prices were greater than the average market price of the common shares, the effect would have been antidilutive. There were no antidilutive shares outstanding at December 31, 2011.

OPCo Revised Depreciation Rates

Effective December 1, 2011, we revised book depreciation rates for certain of OPCo's generating plants consistent with shortened depreciable lives for the generating units. This change in depreciable lives is expected to result in a $54 million increase in depreciation expense in 2012.

Supplementary Information

Related Party Transactions	2011	2010	2009
	Years Ended December 31, (in millions)		
AEP Consolidated Revenues – Utility Operations:			
Ohio Valley Electric Corporation (43.47% owned)	$ -	$ (20)(a)	$ -
AEP Consolidated Revenues – Other Revenues:			
Ohio Valley Electric Corporation – Barging and Other Transportation Services (43.47% Owned)	37	29	31
AEP Consolidated Expenses – Purchased Electricity for Resale:			
Ohio Valley Electric Corporation (43.47% Owned)	383 (b)	302 (b)	286

(a) The AEP Power Pool purchased power from OVEC to serve off-system sales through an agreement that began in January 2010 and ended in June 2010.

(b) The AEP Power Pool purchased power from OVEC to serve retail sales in 2011 and 2010. The total amount reported in 2011 and 2010 includes $66 million and $10 million, respectively, related to these agreements.

Cash Flow Information	2011	2010	2009
	Years Ended December 31, (in millions)		
Cash Paid (Received) for:			
Interest, Net of Capitalized Amounts	$ 900	$ 958	$ 924
Income Taxes	(118)	(268)	(98)
Noncash Investing and Financing Activities:			
Acquisitions Under Capital Leases	54	225	86
Construction Expenditures Included in Current Liabilities at December 31,	380	267	348

2. NEW ACCOUNTING PRONOUNCEMENTS AND EXTRAORDINARY ITEMS

NEW ACCOUNTING PRONOUNCEMENTS

We review the new accounting literature to determine its relevance, if any, to our business. The following represents a summary of final pronouncements that impact our financial statements.

Pronouncements Adopted During 2011

The following standards were adopted during 2011. Consequently, their impact is reflected in the financial statements. The following paragraphs discuss their impact.

ASU 2011-05 "Presentation of Comprehensive Income" (ASU 2011-05)

We adopted ASU 2011-05 effective for the 2011 Annual Report. The standard requires other comprehensive income be presented as part of a single continuous statement of comprehensive income or in a statement of other comprehensive income immediately following the statement of net income.

This standard requires retrospective application to all reporting periods presented in the financial statements. This standard changed the presentation of our financial statements but did not affect the calculation of net income, comprehensive income or earnings per share. The FASB deferred the reclassification adjustment presentation provisions of ASU 2011-05 under the terms in ASU 2011-12, "Comprehensive Income (Topic 220): Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income."

EXTRAORDINARY ITEMS

TCC Texas Restructuring

In February 2006, the PUCT issued an order that denied recovery of capacity auction true-up amounts. Based on the February 2006 PUCT order, TCC recorded the disallowance as a $421 million ($273 million, net of tax) extraordinary loss in the December 31, 2005 financial statements. In July 2011, the Supreme Court of Texas reversed the PUCT's February 2006 disallowance of capacity auction true-up amounts and remanded for reconsideration the treatment of certain tax balances under normalization rules. Based upon the Supreme Court of Texas reversal of the PUCT's capacity auction true-up disallowance, TCC recorded a pretax gain of $421 million ($273 million, net of tax) in Extraordinary Items, Net of Tax on the statements of income in the third quarter of 2011.

Following a remand proceeding, the PUCT allowed TCC to retain contested tax balances in full satisfaction of its true-up proceeding, including carrying charges. Based upon the PUCT order, TCC recorded the reversal of regulatory credits of $65 million ($42 million, net of tax) and the reversal of $89 million of accumulated deferred investment tax credits ($58 million, net of tax) in Extraordinary Items, Net of Tax on the statements of income in the fourth quarter of 2011. See "Texas Restructuring" section of Note AEP_RM.

SWEPCo Texas Restructuring

In August 2006, the PUCT adopted a rule extending the delay in implementation of customer choice in SWEPCo's SPP area of Texas until no sooner than January 1, 2011. In May 2009, the governor of Texas signed a bill related to SWEPCo's SPP area of Texas that requires continued cost of service regulation until certain stages have been completed and approved by the PUCT such that fair competition is available to all Texas retail customer classes. Based upon the signing of the bill, SWEPCo re-applied "Regulated Operations" accounting guidance for the generation portion of SWEPCo's Texas retail jurisdiction effective second quarter of 2009. Management believes that a return to competition in the SPP area of Texas will not occur. The reapplication of "Regulated Operations" accounting guidance resulted in an $8 million ($5 million, net of tax) extraordinary loss.

3. RATE MATTERS

Our subsidiaries are involved in rate and regulatory proceedings at the FERC and their state commissions. Rate matters can have a material impact on net income, cash flows and possibly financial condition. Our recent significant rate orders and pending rate filings are addressed in this note.

OPCo Rate Matters

Ohio Electric Security Plan Filing

2009 – 2011 ESP

The PUCO issued an order in March 2009 that modified and approved the ESP which established rates at the start of the April 2009 billing cycle through 2011. OPCo collected the 2009 annualized revenue increase over the last nine months of 2009. The order also provided a phase-in FAC, which was authorized to be recovered through a non-bypassable surcharge over the period 2012 through 2018 or until securitized. The net FAC deferral as of December 31, 2011 was $521 million, excluding unrecognized equity carrying costs. Collection of the FAC began in January 2012. If OPCo is not ultimately permitted to fully recover its FAC deferral, it would reduce future net income and cash flows and impact financial condition. The PUCO's March 2009 order was appealed to the Supreme Court of Ohio, which issued an opinion and remanded certain issues back to the PUCO.

In October 2011, the PUCO issued an order in the remand proceeding. The order required OPCo to cease POLR billings and apply POLR collections since June 2011 first to the FAC deferral with any remaining balance to be credited to OPCo's customers in November and December 2011. As a result, OPCo recorded a pretax write-off of $47 million on the statement of income related to POLR for the period June 2011 through October 2011. OPCo ceased collection of POLR billings in November 2011. The PUCO order also agreed with OPCo's position that the ESP statute provided a legal basis for reflecting an environmental carrying charge in OPCo's base generation rates. In addition, the PUCO rejected the intervenors' proposed adjustments to the FAC deferral balance for POLR charges and environmental carrying charges for the period from April 2009 through May 2011. In February 2012, the Ohio Consumers' Counsel (OCC) and the Industrial Energy Users-Ohio (IEU) filed appeals with the Supreme Court of Ohio challenging various issues, including the PUCO's refusal to order retrospective relief concerning the POLR charges collected during 2009 – 2011 and various aspects of the approved environmental carrying charge, which if ordered could total up to $698 million, excluding carrying costs.

In January 2011, the PUCO issued an order on the 2009 Significantly Excessive Earnings Test (SEET) filing and determined that 2009 earnings exceeded the PUCO determined threshold by 2.13%. As a result, the PUCO ordered a $43 million refund of pretax earnings to customers, which was recorded in OPCo's 2010 statement of income. The PUCO ordered that the significantly excessive earnings be applied first to the FAC deferral, as of the date of the order, with any remaining balance to be credited to customers on a per kilowatt basis. That credit began with the first billing cycle in February 2011 and continued through December 2011. In May 2011, the IEU and the Ohio Energy Group (OEG) filed appeals with the Supreme Court of Ohio challenging the PUCO's SEET decision. The OEG's appeal seeks the inclusion of off-system sales (OSS) in the calculation of SEET, which, if ordered, could require an additional refund of $22 million based on the PUCO approved SEET calculation. The IEU's appeal also sought the inclusion of OSS as well as other items in the determination of SEET, but did not quantify the amount. Management is unable to predict the outcome of the appeals. If the Supreme Court of Ohio ultimately determines that additional amounts should be refunded, it could reduce future net income and cash flows and impact financial condition.

In July 2011, OPCo filed its 2010 SEET filing with the PUCO based upon the approach in the PUCO's 2009 order. Subsequent testimony and legal briefs from intervenors recommended a refund of up to $62 million of 2010 earnings, which included OSS in the SEET calculation. In December 2011, the PUCO staff filed testimony that recommended a $23 million refund of 2010 earnings. In the fourth quarter of 2011, OPCo provided a reserve based upon management's estimate of the probable amount for a PUCO ordered SEET refund.

OPCo is required to file its 2011 SEET filing with the PUCO in 2012. Management does not currently believe that there are significantly excessive earnings in 2011. Management is unable to predict the outcome of the unresolved litigation discussed above. If these proceedings, including future SEET filings, result in adverse rulings, it could reduce future net income and cash flows and impact financial condition.

January 2012 – May 2016 ESP

In January 2011, OPCo filed an application with the PUCO to approve a new ESP that includes a standard service offer (SSO) pricing for generation. The filed ESP also included alternative energy resource requirements and addressed provisions regarding distribution service, energy efficiency requirements, economic development, job retention in Ohio, generation resources and other matters.

In December 2011, a modified stipulation was approved by the PUCO which involved various issues pending before the PUCO. Various parties, including OPCo, filed requests for rehearing with the PUCO. In February 2012, the PUCO issued an entry on rehearing which rejected the modified stipulation and ordered a return to the 2011 ESP rates until a new rate plan is approved. Under the February 2012 rehearing order, OPCo has 30 days to notify the PUCO whether it plans to modify or withdraw its original application as filed in January 2011. Management is currently evaluating its options and the potential financial and operational impacts on OPCo.

2011 Ohio Distribution Base Rate Case

In February 2011, OPCo filed with the PUCO for an annual increase in distribution rates of $94 million based upon an 11.15% return on common equity to be effective January 2012. In December 2011, a stipulation was approved by the PUCO which provided for no change in distribution rates and a new rider for a $15 million annual credit to residential ratepayers due principally to the inclusion of the rate base distribution investment in the Distribution Investment Rider (DIR). See the "January 2012 – May 2016 ESP" section above. The stipulation also approved recovery of certain distribution regulatory assets of $173 million as of December 31, 2011, excluding $154 million of unrecognized equity carrying costs. These assets and unrecognized carrying costs will be recovered in a distribution asset recovery rider over seven years with an additional long term debt carrying charge, effective January 2012.

Due to the February 2012 PUCO ESP entry on rehearing which rejected the modified stipulation for a new ESP, collection of the DIR terminated. OPCo has the right to withdraw from the stipulation in the distribution base rate case. Management is currently evaluating all its options. If OPCo is not ultimately permitted to fully recover its costs and deferrals, it would reduce future net income and cash flows and impact financial condition.

Sporn Unit 5

In October 2010, OPCo filed an application with the PUCO for the approval of a December 2010 closure of Sporn Unit 5 and the simultaneous establishment of a new non-bypassable distribution rider outside the rate caps established in the 2009 – 2011 ESP proceeding.

In the third quarter of 2011, management decided to no longer offer the output of Sporn Unit 5 into the PJM market. Sporn Unit 5 is not expected to operate in the future, resulting in the removal of Sporn Unit 5 from the AEP Power Pool. As a result, in the third quarter of 2011, OPCo recorded a pretax write-off of $48 million in Asset Impairments and Other Related Charges on the statement of income. In January 2012, the PUCO issued an order which denied recovery of a new non-bypassable distribution rider and declined to exercise jurisdiction over the closure of Sporn Unit 5.

2009 Fuel Adjustment Clause Audit

As required under the ESP orders, the PUCO selected an outside consultant to conduct the audit of the FAC for OPCo for the period of January 2009 through December 2009. In May 2010, the outside consultant provided its confidential audit report to the PUCO. The audit report included a recommendation that the PUCO review whether any proceeds from a 2008 coal contract settlement agreement which totaled $72 million should reduce OPCo's FAC under-recovery balance. Of the total proceeds, approximately $58 million was recognized as a reduction to fuel expense prior to 2009 and $14 million was recognized as a reduction to fuel expense in 2009 and 2010, of which approximately $7 million was the retail jurisdictional share which reduced the FAC deferral in 2009 and 2010.

In January 2012, the PUCO ordered that the remaining $65 million in proceeds from the 2008 coal contract settlement be applied against OPCo's under-recovered fuel balance pending a PUCO decision in OPCo's February 2012 rehearing request. OPCo's rehearing request stated that no additional gain should be credited to the FAC or at most only the retail share of the $58 million gain be applied to the FAC, which approximated $30 million. Further, the January 2012 PUCO order stated that a consultant be hired to review the coal reserve valuation and recommend whether any additional value should benefit ratepayers. Management is unable to predict the outcome of the consultant's recommendation. If the PUCO ultimately determines that additional amounts related to the coal reserve valuation should benefit ratepayers, it could reduce future net income and cash flows and impact financial condition.

2010 Fuel Adjustment Clause Audit

In May 2011, the PUCO-selected outside consultant issued its results of the 2010 FAC audit for OPCo. The audit report included a recommendation that the PUCO reexamine the carrying costs on the deferred FAC balance and determine whether the carrying costs on the balance should be net of accumulated income taxes. As of December 31, 2011, the amount of OPCo's carrying costs that could potentially be at risk is estimated to be $15 million, excluding $17 million of unrecognized equity carrying costs. A decision from the PUCO is pending. Management is unable to predict the outcome of this proceeding. If the PUCO order results in a reduction in the carrying charges related to the FAC deferrals, it would reduce future net income and cash flows and impact financial condition.

Ormet Interim Arrangement

OPCo and Ormet, a large aluminum company, filed an application with the PUCO for approval of an interim arrangement governing the provision of generation service to Ormet. This interim arrangement was approved by the PUCO and was effective from January 2009 through September 2009. In March 2009, the PUCO approved a FAC in the ESP filing and the FAC aspect of the ESP order was upheld by the Supreme Court of Ohio. The approval of the FAC as part of the ESP, together with the PUCO approval of the interim arrangement, provided the basis to record a regulatory asset for the difference between the approved market price and the rate paid by Ormet. Through September 2009, the last month of the interim arrangement, OPCo had $64 million of deferred FAC costs related to the interim arrangement, excluding $2 million of unrecognized equity carrying costs. In November 2009, OPCo requested that the PUCO approve recovery of the deferral under the interim agreement plus a weighted average cost of capital carrying charge. The interim arrangement deferral is included in OPCo's FAC phase-in deferral balance. In the ESP proceeding, intervenors requested that OPCo be required to refund the Ormet-related regulatory asset and requested that the PUCO prevent OPCo from collecting the Ormet-related revenues in the future. The PUCO did not take any action on this request in the 2009-2011 ESP proceeding. The intervenors raised the issue again in response to OPCo's November 2009 filing to approve recovery of the deferral under the interim agreement and this issue remains pending before the PUCO. If OPCo is not ultimately permitted to fully recover its requested deferrals under the interim arrangement, it would reduce future net income and cash flows and impact financial condition.

Economic Development Rider

In April 2010, the Industrial Energy Users-Ohio (IEU) filed a notice of appeal of the 2009 PUCO-approved Economic Development Rider (EDR) with the Supreme Court of Ohio. The EDR collects from ratepayers the difference between the standard tariff and lower contract billings to qualifying industrial customers, subject to PUCO approval. In June 2011, the Supreme Court of Ohio affirmed the PUCO's decision and dismissed the IEU's appeal.

In June 2010, the IEU filed a notice of appeal of the 2010 PUCO-approved EDR with the Supreme Court of Ohio raising the same issues as in the 2009 EDR appeal. In addition, the IEU added a claim that OPCo should not be able to take the benefits of the higher ESP rates while simultaneously challenging the ESP orders. In June 2011, the IEU voluntarily dismissed the 2010 EDR appeal issues that were the same issues dismissed by the Supreme Court of Ohio in its 2009 EDR appeal referenced above. In August 2011, the Supreme Court of Ohio affirmed the PUCO's decision on the remaining issues.

Ohio IGCC Plant

In March 2005, OPCo filed an application with the PUCO seeking authority to recover costs of building and operating an IGCC power plant. Through December 31, 2011, OPCo has collected $24 million in pre-construction costs authorized in a June 2006 PUCO order and has incurred pre-construction costs. Intervenors have filed motions with the PUCO requesting all collected pre-construction costs be refunded to Ohio ratepayers with interest.

Management cannot predict the outcome of any cost recovery litigation concerning the Ohio IGCC plant or what effect, if any, such litigation would have on future net income and cash flows. However, if OPCo is required to refund pre-construction costs collected, it could reduce future net income and cash flows and impact financial condition.

__SWEPCo Rate Matters__

Turk Plant

SWEPCo is currently constructing the Turk Plant, a new base load 600 MW pulverized coal ultra-supercritical generating unit in Arkansas, which is expected to be in service in the fourth quarter of 2012. SWEPCo owns 73% (440 MW) of the Turk Plant and will operate the completed facility. The Turk Plant is currently estimated to cost $1.8 billion, excluding AFUDC, plus an additional $122 million for transmission, excluding AFUDC. SWEPCo's share is currently estimated to cost $1.3 billion, excluding AFUDC, plus the additional $122 million for transmission, excluding AFUDC. As of December 31, 2011, excluding costs attributable to its joint owners and a provision for a Texas capital costs cap, SWEPCo has capitalized approximately $1.4 billion of expenditures (including AFUDC and capitalized interest of $220 million and related transmission costs of $104 million). As of December 31, 2011, the joint owners and SWEPCo have contractual construction obligations of approximately $125 million (including related transmission costs of $8 million). SWEPCo's share of the contractual construction obligations is $94 million.

The APSC granted approval for SWEPCo to build the Turk Plant by issuing a Certificate of Environmental Compatibility and Public Need (CECPN) for the 88 MW SWEPCo Arkansas jurisdictional share of the Turk Plant. Following an appeal by certain intervenors, the Arkansas Supreme Court issued a decision that reversed the APSC's grant of the CECPN. SWEPCo filed a notice with the APSC of its intent to proceed with construction of the Turk Plant but that SWEPCo no longer intends to pursue a CECPN to seek recovery of the originally approved 88 MW portion of Turk Plant costs in Arkansas retail rates.

The PUCT issued an order approving a Certificate of Convenience and Necessity (CCN) for the Turk Plant with the following conditions: (a) a cap on the recovery of jurisdictional capital costs for the Turk Plant based on the previously estimated $1.522 billion projected construction cost, excluding AFUDC and related transmission costs, (b) a cap on recovery of annual CO_2 emission costs at $28 per ton through the year 2030 and (c) a requirement to hold Texas ratepayers financially harmless from any adverse impact related to the Turk Plant not being fully subscribed to by other utilities or wholesale customers. SWEPCo appealed the PUCT's order contending the two cost cap restrictions are unlawful. The Texas Industrial Energy Consumers filed an appeal contending that the PUCT's grant of a conditional CCN for the Turk Plant should be revoked because the Turk Plant is unnecessary to serve retail customers. In February 2010, the Texas District Court affirmed the PUCT's order in all respects. In March 2010, SWEPCo and the Texas Industrial Energy Consumers appealed this decision to the Texas Court of Appeals. In November 2011, the Texas Court of Appeals affirmed the PUCT's order in all respects. As a result, in the fourth quarter of 2011, SWEPCo recorded a pretax write-off of $49 million in Asset Impairments and Other Related Charges on the statement of income related to the estimated excess of the Texas jurisdictional portion of the Turk Plant above the Texas jurisdictional capital costs cap. In December 2011, SWEPCo and the Texas Industrial Energy Consumers filed motions for rehearing at the Texas Court of Appeals which were denied in January 2012. SWEPCo intends to seek review of the Texas Court of Appeals decision at the Supreme Court of Texas.

Several parties, including the Hempstead County Hunting Club, the Sierra Club and the National Audubon Society had challenged the air permit, the wastewater discharge permit and the wetlands permit that were issued for the Turk Plant. Those parties also sought a temporary restraining order and preliminary injunction to stop construction of the Turk Plant. The motion for preliminary injunction was partially granted in 2010. In 2011, SWEPCo entered into settlement agreements with these parties which resolved all outstanding issues related to the permits and the APSC's grant of a CECPN. The parties dismissed all pending permit and CECPN challenges at the APSC, other administrative agencies and the courts.

If SWEPCo cannot recover all of its investment and expenses related to the Turk Plant, it would materially reduce future net income and cash flows and materially impact financial condition.

Texas Turk Plant Rate Plan

In August 2011, SWEPCo requested approval of a plan from the PUCT for including the Turk Plant investment in Texas retail rates. SWEPCo's application was dismissed in December 2011. The PUCT stated that, as a matter of policy, the PUCT would not order a return on CWIP outside of a full base rate case proceeding. SWEPCo intends to file a full base rate case in 2012 with a proposed rate increase closely aligned with the commercial operation date of the Turk Plant.

<u>TCC Rate Matters</u>

TEXAS RESTRUCTURING

Texas Restructuring Appeals

Pursuant to PUCT restructuring orders, TCC securitized net recoverable stranded generation costs of $2.5 billion and is recovering the principal and interest on the securitization bonds through the end of 2020. TCC also refunded other net true-up regulatory liabilities of $375 million during the period October 2006 through June 2008 via a CTC credit rate rider under PUCT restructuring orders. TCC and intervenors appealed the PUCT's true-up related orders. After rulings from the Texas District Court and the Texas Court of Appeals, TCC, the PUCT and intervenors filed petitions for review with the Supreme Court of Texas. In July 2011, the Supreme Court of Texas issued its opinion reversing the PUCT's 2006 order denying recovery of capacity auction true-up amounts and remanding for reconsideration the treatment of certain tax balances under normalization rules. In December 2011, the PUCT approved an unopposed stipulation allowing TCC to recover $800 million, including carrying charges, and retain contested tax balances in full satisfaction of its true-up proceeding. The following actions resulted from these decisions:

- Based upon the Supreme Court of Texas' reversal of the PUCT's capacity auction true-up disallowance, TCC recorded $421 million of pretax income ($273 million, net of tax) in Extraordinary Items, Net of Tax on the statement of income in the third quarter of 2011.

- In 2011, TCC recorded $271 million in pretax Carrying Costs Income on the statement of income related to the debt component of carrying costs for the period from January 2002 through December 2011. This carrying costs income represents previously unrecorded earnings associated with restructuring in Texas since 2002. The total regulatory asset related to the capacity auction true-up as of December 31, 2011 was $692 million, excluding unrecognized equity carrying costs. TCC plans to continue to recognize debt carrying costs income until securitization occurs and plans to recognize equity carrying costs income as collected from customers over the life of the securitization.

- The PUCT allowed TCC to retain contested tax balances in full satisfaction of its true-up proceeding, including carrying charges. TCC recorded the reversal of regulatory credits of $65 million ($42 million, net of tax) in Extraordinary Items, Net of Tax on the statement of income in the fourth quarter of 2011. Also, in the fourth quarter of 2011, TCC recorded $52 million in pretax Carrying Costs Income on the statement of income. TCC also recorded the reversal of $89 million of accumulated deferred investment tax credits ($58 million, net of tax) in Extraordinary Items, Net of Tax on the statement of income in the fourth quarter of 2011. See the "TCC Deferred Investment Tax Credits and Excess Deferred Federal Income Taxes" section below.

- The Supreme Court of Texas reversed the Texas Court of Appeals' decision and found that the PUCT could adjust the net book value for what it determined to be commercially unreasonable conduct. This portion of the decision is unfavorable, but was already reflected in the financial statements.

- The Supreme Court of Texas affirmed the PUCT's finding that the sales price should be used to value TCC's nuclear generation. This portion of the decision is favorable, but this issue will have no impact on TCC's rate recovery as this was already reflected in the financial statements.

- The Supreme Court of Texas reversed the Texas Court of Appeals' decision and found it was appropriate for the PUCT to take into account previously refunded excess mitigation credits to affiliate retail electricity providers. This portion of the decision upheld the PUCT's decision.

- The PUCT decisions allowing recovery of construction work in progress balances and specifying the interest rate on stranded costs were upheld. These decisions are already reflected in the financial statements and were not addressed in the remand proceeding.

The approved stipulation resolved all remaining issues in these dockets. In December 2011, TCC filed an application with the PUCT for a financing order to recover the $800 million through the issuance of securitization bonds as permitted by Texas statutory provisions. In January 2012, the PUCT approved the request. TCC anticipates issuing the bonds in March 2012.

TCC Deferred Investment Tax Credits and Excess Deferred Federal Income Taxes

In 2006, the PUCT reduced recovery of the amount securitized by $103 million of tax benefits including associated carrying costs related to TCC's generation assets. In 2006, TCC obtained a private letter ruling from the IRS which confirmed that such a reduction was an IRS normalization violation. In 2008, the IRS issued final regulations, which supported the IRS's private letter ruling which would make the refunding of or the reduction of the amount securitized by such tax benefits a normalization violation. After the IRS issued its final regulations, the tax normalization issue was remanded to the PUCT for its consideration of additional evidence including the IRS regulations. In December 2011, the PUCT approved an unopposed stipulation allowing TCC to retain contested tax balances in full satisfaction of its true-up proceeding, including carrying charges, in final resolution of this issue. See the "Texas Restructuring Appeals" section above.

TCC Excess Earnings

In 2005, a Texas appellate court issued a decision finding that a PUCT order requiring TCC to refund to the Texas Retail Electric Providers excess earnings prior to and outside of the true-up process was unlawful under the Texas Restructuring Legislation. From 2002 to 2005, TCC refunded $55 million of excess earnings, including interest, under the overturned PUCT order. In the true-up proceeding, the PUCT adjusted stranded costs for TCC's payment of excess earnings under the PUCT order. However, the PUCT did not properly recognize TCC's payment of interest under the prior order, causing TCC to refund interest twice. The Supreme Court of Texas approved the PUCT treatment of these matters in the true-up case, noting that TCC could pursue its additional interest claim in further proceedings related to the excess earnings order. TCC agreed to dismiss its claims as part of the stipulation approved by the PUCT in the true-up proceeding. See the "Texas Restructuring Appeals" section above. The dismissal did not have any impact on TCC's rate recovery as this was already reflected in the financial statements.

APCo and WPCo Rate Matters

2011 Virginia Biennial Base Rate Case

In March 2011, APCo filed a generation and distribution base rate request with the Virginia SCC to increase annual base rates by $126 million based upon an 11.65% return on common equity. The return on common equity included a requested 0.5% renewable portfolio standards (RPS) incentive as allowed by law.

In November 2011, the Virginia SCC issued an order which approved a $55 million increase in generation and distribution base rates, effective February 2012, and a 10.9% return on common equity, which included a 0.5% RPS incentive. The $55 million increase included $39 million related to an increase in depreciation rates.

Rate Adjustment Clauses

In 2007, the Virginia law governing the regulation of electric utility service was amended to, among other items, provide for rate adjustment clauses (RACs) beginning in January 2009 for the timely and current recovery of costs of: (a) transmission services billed by an RTO, (b) demand side management and energy efficiency programs, (c) renewable energy programs, (d) environmental compliance projects and (e) new generation facilities, including major unit modifications. In accordance with Virginia law, APCo is deferring incremental environmental costs incurred after December 2008 and renewable energy costs incurred after December 2007 which are not being recovered in current revenues. As of December 31, 2011, APCo has deferred $24 million of environmental costs, excluding $6 million of unrecognized equity carrying costs, incurred from January 2009 through December 2010, $18 million of environmental costs, excluding $4 million of unrecognized equity carrying costs, incurred in 2011 and $44 million of renewable energy costs.

In March 2011, APCo filed for approval of an environmental RAC, a renewable energy program RAC and a generation RAC. The environmental RAC requested recovery of $77 million of incremental environmental compliance costs incurred from January 2009 through December 2010. The renewable energy program RAC requested recovery of $6 million for the incremental portion of deferred wind power costs for the Camp Grove and Fowler Ridge projects through December 2010. The generation RAC requested recovery of the Dresden Plant, which was placed into service in January 2012. With Virginia SCC approval, APCo purchased the Dresden Plant from AEGCo in August 2011 for $302 million.

In August 2011, a stipulation was filed with the Virginia SCC related to the generation RAC. The stipulation requested recovery of the Dresden Plant costs totaling up to $27 million annually, effective March 2012. In January 2012, the Virginia SCC issued an order which modified and approved the stipulation to allow APCo to recover $26 million annually, effective March 2012.

In November 2011, the Virginia SCC issued an order which approved recovery of $6 million for the incremental portion of deferred wind power costs for the Camp Grove and Fowler Ridge projects, effective February 2012. In addition, the order found that APCo can recover the non-incremental deferred wind power costs of $27 million as of December 31, 2011 through the FAC.

Also in November 2011, the Virginia SCC issued an order which approved environmental RAC recovery of $30 million to be collected over one year beginning in February 2012. The Virginia SCC denied recovery of certain environmental costs. As a result, in the fourth quarter of 2011, APCo recorded a pretax write-off of $31 million on the statement of income related to environmental compliance costs incurred from January 2009 through December 2010. In December 2011, APCo filed a notice of appeal with the Supreme Court of Virginia regarding the Virginia SCC's environmental RAC decision. If the Virginia SCC were to disallow a portion of APCo's deferred environmental compliance costs incurred since January 2011, it would reduce future net income and cash flows.

2010 West Virginia Base Rate Case

In May 2010, APCo and WPCo filed a request with the WVPSC to increase annual base rates by $156 million based upon an 11.75% return on common equity. In March 2011, the WVPSC modified and approved a settlement agreement which increased annual base rates by approximately $51 million based upon a 10% return on common equity, effective April 2011. The settlement agreement also resulted in a pretax write-off of a portion of the Mountaineer Carbon Capture and Storage Product Validation Facility in March 2011. See "Mountaineer Carbon Capture and Storage Project" section below. In addition, the WVPSC allowed APCo to defer and amortize $18 million of previously expensed 2009 incremental storm expenses and allowed APCo and WPCo to defer and amortize $15 million of previously expensed costs related to the 2010 cost reduction initiatives, each over a period of seven years.

Mountaineer Carbon Capture and Storage Project

Product Validation Facility (PVF)

APCo and ALSTOM Power, Inc., an unrelated third party, jointly constructed a CO_2 capture validation facility, which was placed into service in September 2009. APCo also constructed and owns the necessary facilities to store the CO_2. In October 2009, APCo started injecting CO_2 into the underground storage facilities. The injection of CO_2 required the recording of an asset retirement obligation and an offsetting regulatory asset. In May 2011, the PVF ended operations.

In APCo's and WPCo's May 2010 West Virginia base rate filing, APCo and WPCo requested rate base treatment of the PVF, including recovery of the related asset retirement obligation regulatory asset amortization and accretion. In March 2011, a WVPSC order denied the request for rate base treatment of the PVF largely due to its experimental operation. The base rate order provided that should APCo construct a commercial scale carbon capture and sequestration (CCS) facility, only the West Virginia portion of the PVF costs, based on load sharing among certain AEP operating companies, may be considered used and useful plant in service and included in future rate base. See "2010 West Virginia Base Rate Case" section above. In 2011, APCo recorded a net pretax write-off of $14 million in Other Operation expense on the statement of income related to the write-off of a portion of the West Virginia jurisdictional share of the PVF offset by an asset retirement obligation adjustment. As of December 31, 2011, APCo has recorded $14 million in Regulatory Assets on the balance sheet related to the PVF. If APCo cannot recover its remaining PVF investment and related accretion expenses, it would reduce future net income and cash flows.

Carbon Capture and Sequestration Project with the Department of Energy (DOE) (Commercial Scale Project)

During 2010, AEPSC, on behalf of APCo, began the project definition stage for the potential construction of a new commercial scale CCS facility at the Mountaineer Plant. The DOE agreed to fund 50% of allowable costs incurred for the CCS facility up to a maximum of $334 million. A Front-End Engineering and Design (FEED) study was completed during the third quarter of 2011. Management postponed any further CCS project activities because of the uncertainty about the regulation of CO_2. In June 2011, the FEED study costs were allocated among the AEP East companies, PSO and SWEPCo based on eligible plants that could potentially benefit from the carbon capture. As of December 31, 2011, APCo has incurred $34 million in total project costs and has received $20 million of DOE and other eligible funding resulting in $14 million of net costs, of which $8 million was written off. The remaining $6 million in net costs are recorded in Regulatory Assets on the balance sheet. If the costs of the CCS project cannot be recovered, it would reduce future net income and cash flows.

APCo's Filings for an IGCC Plant

Through December 31, 2011, APCo deferred for future recovery pre-construction IGCC costs of approximately $9 million applicable to its West Virginia jurisdiction, approximately $2 million applicable to its FERC jurisdiction and approximately $9 million applicable to its Virginia jurisdiction. APCo will not start construction of the IGCC plant until sufficient assurance of full cost recovery exists in Virginia and West Virginia. If the plant is cancelled, APCo plans to seek recovery of its prudently incurred deferred pre-construction costs. If the costs are not recoverable, it would reduce future net income and cash flows and impact financial condition.

APCo's and WPCo's Expanded Net Energy Charge (ENEC) Filing

In September 2009, the WVPSC issued an order approving APCo's and WPCo's March 2009 ENEC request. The approved order provided for recovery of an under-recovered balance plus a projected increase in ENEC costs over a four-year phase-in period with an overall increase of $355 million and a first-year increase of $124 million, effective October 2009.

In June 2010, the WVPSC approved a settlement agreement for $96 million, including $10 million of construction surcharges related to APCo's and WPCo's second year ENEC increase. The settlement agreement allows APCo to accrue a weighted average cost of a capital carrying charge on the excess under-recovery balance due to the ENEC phase-in as adjusted for the impacts of accumulated deferred income taxes. The new rates became effective in July 2010.

In June 2011, the WVPSC issued an order approving a $98 million annual increase including $8 million of construction surcharges and $8 million of carrying charges related to APCo's and WPCo's third year ENEC increase. The order also allows APCo to accrue a fixed annual carrying cost rate of 4%. The new rates became effective in July 2011. Additionally, the order approved APCo's request to purchase the Dresden Plant from AEGCo and approved deferral of post in-service Dresden Plant costs, including a return, for future recovery. APCo purchased the Dresden Plant from AEGCo in August 2011 for $302 million. As of December 31, 2011, APCo's ENEC under-recovery balance of $359 million was recorded in Regulatory Assets on the balance sheet, excluding $7 million of unrecognized equity carrying costs. If the WVPSC were to disallow a portion of APCo's and WPCo's deferred ENEC costs, it could reduce future net income and cash flows and impact financial condition.

PSO Rate Matters

PSO 2008 Fuel and Purchased Power

In July 2009, the OCC initiated a proceeding to review PSO's fuel and purchased power adjustment clause for the calendar year 2008 and also initiated a prudence review of the related costs. In March 2010, the Oklahoma Attorney General and the Oklahoma Industrial Energy Consumers (OIEC) recommended the fuel clause adjustment rider be amended so that the shareholder's portion of off-system sales margins decrease from 25% to 10%. The OIEC also recommended that the OCC conduct a comprehensive review of all affiliate fuel transactions during 2007 and 2008. In July 2010, additional testimony regarding the 2007 transfer of ERCOT trading contracts to AEPEP was filed. The testimony included unquantified refund recommendations relating to re-pricing of those ERCOT trading contracts. Hearings were held in June 2011. If the OCC were to issue an unfavorable decision, it could reduce future net income and cash flows and impact financial condition.

I&M Rate Matters

Michigan 2009 and 2010 Power Supply Cost Recovery (PSCR) Reconciliation (Cook Plant Unit 1 Fire and Shutdown)

In March 2010, I&M filed its 2009 PSCR reconciliation with the MPSC. The filing included an adjustment to exclude from the PSCR the incremental fuel cost of replacement power due to the Cook Plant Unit 1 (Unit 1) outage from mid-December 2008 through December 2009, the period during which I&M received and recognized accidental outage insurance proceeds. In October 2010, a settlement agreement was filed with the MPSC which included deferring the Unit 1 outage issue to the 2010 PSCR reconciliation. In November 2011, the MPSC approved a settlement agreement for the 2010 PSCR reconciliation which resolved the Unit 1 outage issue by ordering no disallowances associated with the Unit 1 outage issue. See the "Cook Plant Unit 1 Fire and Shutdown" section of Note 5.

2011 Michigan Base Rate Case

In July 2011, I&M filed a request with the MPSC for an annual increase in Michigan base rates of $25 million and a return on common equity of 11.15%. The request included an increase in depreciation rates that would result in a $6 million increase in annual depreciation expense. An interim rate increase of $16 million annually was implemented in January 2012, subject to refund.

In February 2012, the MPSC approved a settlement agreement which increased annual base rates by approximately $15 million, effective April 2012, based upon a return on common equity of 10.2% and included a $5 million annual increase in depreciation rates. The approved settlement agreement also excluded the Michigan jurisdictional share of the net costs of the Cook Plant Unit 1 (Unit 1) turbine replacement from rate base but provided for a return on and of the net cost as a regulatory asset, effective February 2012. As of December 31, 2011, the Michigan jurisdictional share of the net costs of the Unit 1 turbine replacement was $9 million. Future rate recovery of the regulatory asset will be reviewed in a future rate proceeding.

2011 Indiana Base Rate Case

In September 2011, I&M filed a request with the IURC for a net annual increase in Indiana base rates of $149 million based upon a return on common equity of 11.15%. The request included an increase in depreciation rates that would result in a $25 million increase in annual depreciation expense.

<u>FERC Rate Matters</u>

Seams Elimination Cost Allocation (SECA) Revenue Subject to Refund

In 2004, AEP eliminated transaction-based through-and-out transmission service charges and collected, at the FERC's direction, load-based charges, referred to as RTO SECA through March 2006. Intervenors objected and the FERC set SECA rate issues for hearing and ordered that the SECA rate revenues be collected, subject to refund. The AEP East companies recognized gross SECA revenues of $220 million. In 2006, a FERC Administrative Law Judge issued an initial decision finding that the SECA rates charged were unfair, unjust and discriminatory and that new compliance filings and refunds should be made.

AEP filed briefs jointly with other affected companies asking the FERC to reverse the decision. In May 2010, the FERC issued an order that generally supported AEP's position and required a compliance filing to be filed with the FERC by August 2010. In August 2010, the affected companies, including the AEP East companies, filed a compliance filing with the FERC. If the compliance filing is accepted, the AEP East companies would have to pay refunds of approximately $20 million including estimated interest of $5 million. The AEP East companies could also potentially receive payments up to approximately $10 million including estimated interest of $3 million. A decision is pending from the FERC.

The FERC has approved settlements applicable to $112 million of SECA revenue. The AEP East companies provided reserves for net refunds for SECA settlements applicable to the remaining $108 million of SECA revenues collected. Based on the analysis of the May 2010 order and the compliance filing, management believes that the reserve is adequate to pay the refunds, including interest, that will be required should the compliance filing be made final. Management cannot predict the ultimate outcome of this proceeding at the FERC which could impact future net income and cash flows.

Possible Termination of the Interconnection Agreement

In December 2010, each of the AEP Power Pool members gave notice to AEPSC and each other of their decision to terminate the Interconnection Agreement effective January 2014 or such other date approved by FERC, subject to state regulatory input. In February 2012, an application was filed with the FERC proposing to establish a new power cost sharing agreement between APCo, I&M and KPCo. If any of the AEP Power Pool members experience decreases in revenues or increases in costs as a result of the termination of the AEP Power Pool and are unable to recover the change in revenues and costs through rates, prices or additional sales, it could reduce future net income and cash flows. As a result of the February 2012 ESP rehearing order, management is in the process of withdrawing the PUCO and FERC applications. See "January 2012 – May 2016 ESP" section of the OPCo rate matters.

PJM/MISO Market Flow Calculation Settlement Adjustments

During 2009, an analysis conducted by MISO and PJM discovered several instances of unaccounted for power flows on numerous coordinated flowgates. These flows affected the settlement data for congestion revenues and expenses and dated back to the start of the MISO market in 2005. In January 2011, PJM and MISO reached a settlement agreement where the parties agreed to net various issues to zero. In June 2011, the FERC approved the settlement agreement.

4. EFFECTS OF REGULATION

Regulatory assets are comprised of the following items:

	December 31, 2011	December 31, 2010	Remaining Recovery Period
Current Regulatory Assets	(in millions)		
Under-recovered Fuel Costs - earns a return	$ 56	$ 73	1 year
Under-recovered Fuel Costs - does not earn a return	9	8	1 year
Total Current Regulatory Assets	$ 65	$ 81	
Noncurrent Regulatory Assets			
Regulatory assets not yet being recovered pending future proceedings to determine the recovery method and timing:			
Regulatory Assets Currently Earning a Return			
Storm Related Costs	$ 24	$ 55	
Economic Development Rider	13	6	
Customer Choice Deferrals	-	59	
Line Extension Carrying Costs	-	55	
Acquisition of Monongahela Power	-	8	
Other Regulatory Assets Not Yet Being Recovered	-	1	
Regulatory Assets Currently Not Earning a Return			
Deferred Wind Power Costs	38	29	
Environmental Rate Adjustment Clause	18	56	
Mountaineer Carbon Capture and Storage Product Validation Facility	14	60	
Special Rate Mechanism for Century Aluminum	13	13	
Litigation Settlement	11	-	
Storm Related Costs	10	45	
Acquisition of Monongahela Power	-	4	
Other Regulatory Assets Not Yet Being Recovered	14	4	
Total Regulatory Assets Not Yet Being Recovered	155	395	
Regulatory assets being recovered:			
Regulatory Assets Currently Earning a Return			
Capacity Auction True-Up	692	-	13 years
Fuel Adjustment Clause	521	476	7 years
Expanded Net Energy Charge	327	361	2 years
Distribution Asset Recovery Rider	173	-	7 years
Unamortized Loss on Reacquired Debt	92	93	32 years
Storm Related Costs	65	38	7 years
Meter Replacement Costs	39	4	29 years
Transmission Cost Recovery Rider	28	-	2 years
RTO Formation/Integration Costs	18	21	8 years
Economic Development Rider	12	1	1 year
Red Rock Generating Facility	10	10	45 years
Other Regulatory Assets Being Recovered	15	17	various
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	2,308	2,161	13 years
Income Taxes, Net	1,237	1,097	37 years
Postemployment Benefits	47	51	4 years
Cook Nuclear Plant Refueling Outage Levelization	41	54	2 years
Storm Related Costs	35	21	7 years
Expanded Net Energy Charge	32	-	6 years
Environmental Rate Adjustment Clause	24	-	2 years
Deferred PJM Fees	22	7	1 year
Transmission Rate Adjustment Clause	20	19	2 years
Deferred Restructuring Costs	18	6	7 years
Unrealized Loss on Forward Commitments	16	10	2 years
Asset Retirement Obligation	14	15	9 years
Vegetation Management	11	13	1 year
Restructuring Transition Costs	8	14	5 years
Off-system Sales Margin Sharing	-	13	
Other Regulatory Assets Being Recovered	46	46	various
Total Regulatory Assets Being Recovered	5,871	4,548	
Total Noncurrent Regulatory Assets	$ 6,026	$ 4,943	

Regulatory liabilities are comprised of the following items:

	December 31, 2011	December 31, 2010	Remaining Refund Period
Current Regulatory Liabilities	(in millions)		
Over-recovered Fuel Costs - pays a return	$ 5	$ 16	1 year
Over-recovered Fuel Costs - does not pay a return	3	1	1 year
Total Current Regulatory Liabilities	$ 8	$ 17	
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities not yet being paid:			
Regulatory Liabilities Currently Paying a Return			
Refundable Construction Financing Costs	$ 53	$ 20	
Other Regulatory Liabilities Not Yet Being Paid	5	-	
Regulatory Liabilities Currently Not Paying a Return			
Over-recovery of Costs Related to gridSMART®	4	10	
Other Regulatory Liabilities Not Yet Being Paid	4	11	
Total Regulatory Liabilities Not Yet Being Paid	66	41	
Regulatory liabilities being paid:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	2,270	2,222	(a)
Advanced Metering Infrastructure Surcharge	78	61	9 years
Deferred Investment Tax Credits	27	32	11 years
Excess Earnings	13	13	42 years
Other Regulatory Liabilities Being Paid	4	4	various
Regulatory Liabilities Currently Not Paying a Return			
Excess Asset Retirement Obligations for Nuclear Decommissioning Liability	377	354	(b)
Deferred Investment Tax Credits	144	242	75 years
Spent Nuclear Fuel Liability	43	42	(b)
Unrealized Gain on Forward Commitments	41	60	5 years
Over-recovery of Transition Charges	41	38	10 years
Energy Efficiency/Peak Demand Reduction	40	10	1 year
Deferred State Income Tax Coal Credits	29	29	10 years
Over-recovery of PJM Expenses	-	12	
Other Regulatory Liabilities Being Paid	22	11	various
Total Regulatory Liabilities Being Paid	3,129	3,130	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 3,195	$ 3,171	

(a) Relieved as removal costs are incurred.
(b) Relieved when plant is decommissioned.

5. COMMITMENTS, GUARANTEES AND CONTINGENCIES

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

COMMITMENTS

Construction and Commitments

The AEP System has substantial construction commitments to support its operations and environmental investments. In managing the overall construction program and in the normal course of business, we contractually commit to third-party construction vendors for certain material purchases and other construction services. We forecast approximately $3.1 billion of construction expenditures, excluding equity AFUDC and capitalized interest, for 2012. The subsidiaries purchase fuel, materials, supplies, services and property, plant and equipment under contract as part of their normal course of business. Certain supply contracts contain penalty provisions for early termination.

The following table summarizes our actual contractual commitments at December 31, 2011:

Contractual Commitments	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 2,867	$ 3,918	$ 2,574	$ 3,108	$ 12,467
Energy and Capacity Purchase Contracts (b)	104	213	217	1,066	1,600
Construction Contracts for Capital Assets (c)	60	-	-	-	60
Total	$ 3,031	$ 4,131	$ 2,791	$ 4,174	$ 14,127

(a) Represents contractual commitments to purchase coal, natural gas, uranium and other consumables as fuel for electric generation along with related transportation of the fuel.
(b) Represents contractual commitments for energy and capacity purchase contracts.
(c) Represents only capital assets for which we have signed contracts. Actual payments are dependent upon and may vary significantly based upon the decision to build, regulatory approval schedules, timing and escalation of project costs.

GUARANTEES

We record liabilities for guarantees in accordance with the accounting guidance for "Guarantees." There is no collateral held in relation to any guarantees. In the event any guarantee is drawn, there is no recourse to third parties unless specified below.

Letters of Credit

We enter into standby letters of credit with third parties. As Parent, we issue all of these letters of credit in our ordinary course of business on behalf of our subsidiaries. These letters of credit cover items such as gas and electricity risk management contracts, construction contracts, insurance programs, security deposits and debt service reserves.

We have credit facilities totaling $3.25 billion, under which we may issue up to $1.35 billion as letters of credit. In July 2011, we replaced the $1.5 billion facility due in 2012 with a new $1.75 billion facility maturing in July 2016 and extended the $1.5 billion facility due in 2013 to expire in June 2015. As of December 31, 2011, the maximum future payments for letters of credit issued under the two credit facilities were $134 million with maturities ranging from January 2012 to October 2012.

In March 2011, we terminated a $478 million credit agreement that was scheduled to mature in April 2011 and was used to support $472 million of variable rate Pollution Control Bonds. In March 2011, we remarketed $357 million of variable rate Pollution Control Bonds supported by bilateral letters of credit for $361 million. The letters of credit have maturities ranging from March 2013 to March 2014. The remaining $115 million of Pollution Control Bonds were reacquired and are held by trustees.

In July 2011, we remarketed $45 million of variable rate Pollution Control Bonds supported by bilateral letters of credit for $46 million. The letters of credit mature in July 2014.

Guarantees of Third-Party Obligations

SWEPCo

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provides guarantees of mine reclamation. In July 2011, SWEPCo's guarantee was increased from $65 million to $100 million due to expansion of the mining area. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by Sabine. This guarantee ends upon depletion of reserves and completion of final reclamation. Based on the latest study, we estimate the reserves will be depleted in 2036 with final reclamation completed by 2046 at an estimated cost of approximately $58 million. As of December 31, 2011, SWEPCo has collected approximately $54 million through a rider for final mine closure and reclamation costs, of which $2 million is recorded in Other Current Liabilities, $22 million is recorded in Deferred Credits and Other Noncurrent Liabilities and $30 million is recorded in Asset Retirement Obligations on our balance sheets.

Sabine charges SWEPCo, its only customer, all of its costs. SWEPCo passes these costs to customers through its fuel clause.

Indemnifications and Other Guarantees

Contracts

We enter into several types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, our exposure generally does not exceed the sale price. The status of certain sale agreements is discussed in the "Dispositions" section of Note 6. As of December 31, 2011, there were no material liabilities recorded for any indemnifications.

Lease Obligations

We lease certain equipment under master lease agreements. See "Master Lease Agreements" and "Railcar Lease" sections of Note 12 for disclosure of lease residual value guarantees.

ENVIRONMENTAL CONTINGENCIES

Carbon Dioxide Public Nuisance Claims

In 2004, eight states and the City of New York filed an action in Federal District Court for the Southern District of New York against AEP, AEPSC, Cinergy Corp, Xcel Energy, Southern Company and Tennessee Valley Authority. The Natural Resources Defense Council, on behalf of three special interest groups, filed a similar complaint against the same defendants. The actions allege that CO_2 emissions from the defendants' power plants constitute a public nuisance under federal common law due to impacts of global warming and sought injunctive relief in the form of specific emission reduction commitments from the defendants. The trial court dismissed the lawsuits.

In September 2009, the Second Circuit Court of Appeals issued a ruling on appeal remanding the cases to the Federal District Court for the Southern District of New York. The Second Circuit held that the issues of climate change and global warming do not raise political questions and that Congress' refusal to regulate CO_2 emissions does not mean that plaintiffs must wait for an initial policy determination by Congress or the President's administration to secure the relief sought in their complaints. In 2010, the U.S. Supreme Court granted the defendants' petition for review. In June 2011, the U.S. Supreme Court reversed and remanded the case to the Court of Appeals, finding that plaintiffs' federal common law claims are displaced by the regulatory authority granted to the Federal EPA under the CAA. After the remand, the plaintiffs asked the Second Circuit to return the case to the district court so that they could withdraw their complaints. The cases were returned to the district court and the plaintiffs' federal common law claims were dismissed in December 2011.

In October 2009, the Fifth Circuit Court of Appeals reversed a decision by the Federal District Court for the District of Mississippi dismissing state common law nuisance claims in a putative class action by Mississippi residents asserting that CO_2 emissions exacerbated the effects of Hurricane Katrina. The Fifth Circuit held that there was no exclusive commitment of the common law issues raised in plaintiffs' complaint to a coordinate branch of government and that no initial policy determination was required to adjudicate these claims. The court granted petitions for rehearing. An additional recusal left the Fifth Circuit without a quorum to reconsider the decision and the appeal was dismissed, leaving the district court's decision in place. Plaintiffs filed a petition with the U.S. Supreme Court asking the court to remand the case to the Fifth Circuit and reinstate the panel decision. The petition was denied in January 2011. Plaintiffs refiled their complaint in federal district court. The court ordered all defendants to respond to the refiled complaints in October 2011. We believe the claims are without merit, and in addition to other defenses, are barred by the doctrine of collateral estoppel and the applicable statute of limitations. We intend to defend against the claims. We are unable to determine a range of potential losses that are reasonably possible of occurring.

Alaskan Villages' Claims

In 2008, the Native Village of Kivalina and the City of Kivalina, Alaska filed a lawsuit in Federal Court in the Northern District of California against AEP, AEPSC and 22 other unrelated defendants including oil and gas companies, a coal company and other electric generating companies. The complaint alleges that the defendants' emissions of CO_2 contribute to global warming and constitute a public and private nuisance and that the defendants are acting together. The complaint further alleges that some of the defendants, including AEP, conspired to create a false scientific debate about global warming in order to deceive the public and perpetuate the alleged nuisance. The plaintiffs also allege that the effects of global warming will require the relocation of the village at an alleged cost of $95 million to $400 million. In October 2009, the judge dismissed plaintiffs' federal common law claim for nuisance, finding the claim barred by the political question doctrine and by plaintiffs' lack of standing to bring the claim. The judge also dismissed plaintiffs' state law claims without prejudice to refiling in state court. The plaintiffs appealed the decision. The defendants requested that the court defer setting this case for oral argument until after the Supreme Court issues its decision in the CO_2 public nuisance case discussed above. The court accepted supplemental briefing on the impact of the Supreme Court's decision and heard oral argument in November 2011. We believe the action is without merit and intend to defend against the claims. We are unable to determine a range of potential losses that are reasonably possible of occurring.

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

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

Superfund addresses clean-up of hazardous substances that have been released to the environment. The Federal EPA administers the clean-up programs. Several states have enacted similar laws. At December 31, 2011, our subsidiaries are named by the Federal EPA as a Potentially Responsible Party (PRP) for four sites for which alleged liability is unresolved. There are nine additional sites for which our subsidiaries have received information requests which could lead to PRP designation. Our subsidiaries have also been named potentially liable at four sites under state law including the I&M site discussed in the next paragraph. In those instances where we have been named a PRP or defendant, our disposal or recycling activities were in accordance with the then-applicable laws and regulations. Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories. Liability has been resolved for a number of sites with no significant effect on net income.

In 2008, I&M received a letter from the Michigan Department of Environmental Quality (MDEQ) concerning conditions at a site under state law and requesting I&M take voluntary action necessary to prevent and/or mitigate public harm. I&M started remediation work in accordance with a plan approved by MDEQ. I&M's provision is approximately $10 million. As the remediation work is completed, I&M's cost may continue to increase as new information becomes available concerning either the level of contamination at the site or changes in the scope of remediation required by the MDEQ. We cannot predict the amount of additional cost, if any.

We evaluate the potential liability for each Superfund site separately, but several general statements can be made about our potential future liability. Allegations that materials were disposed at a particular site are often unsubstantiated and the quantity of materials deposited at a site can be small and often nonhazardous. Although Superfund liability has been interpreted by the courts as joint and several, typically many parties are named as PRPs for each site and several of the parties are financially sound enterprises. At present, our estimates do not anticipate material cleanup costs for any of our identified Superfund sites, except the I&M site discussed above.

Amos Plant – State and Federal Enforcement Proceedings

In March 2010, we received a letter from the West Virginia Department of Environmental Protection, Division of Air Quality (DAQ), alleging that at various times in 2007 through 2009 the units at Amos Plant reported periods of excess opacity (indicator of compliance with PM emission limits) that lasted for more than 30 consecutive minutes in a 24-hour period and that certain required notifications were not made. We met with representatives of DAQ to discuss these occurrences and the steps we have taken to prevent a recurrence. DAQ indicated that additional enforcement action may be taken, including imposition of a civil penalty of approximately $240 thousand. We have denied that violations of the reporting requirements occurred and maintain that the proper reporting was done. In March 2011, we resolved these issues through the entry of a consent order that included the payment of a $75 thousand civil penalty and certain improvements in our opacity reports.

In March 2010, we received a request to show cause from the Federal EPA alleging that certain reporting requirements under Superfund and the Emergency Planning and Community Right-to-Know Act had been violated and inviting us to engage in settlement negotiations. The request includes a proposed civil penalty of approximately $300 thousand. We provided additional information to representatives of the Federal EPA. Based on the information we submitted, the Federal EPA determined that it will not further pursue enforcement for several alleged violations and we agreed to resolve the remaining allegations through a consent order that includes payment of a $36 thousand civil penalty.

NUCLEAR CONTINGENCIES

I&M owns and operates the two-unit 2,191 MW Cook Plant under licenses granted by the Nuclear Regulatory Commission (NRC). We have a significant future financial commitment to dispose of SNF and to safely decommission and decontaminate the plant. The licenses to operate the two nuclear units at the Cook Plant expire in 2034 and 2037. The operation of a nuclear facility also involves special risks, potential liabilities and specific regulatory and safety requirements. By agreement, I&M is partially liable, together with all other electric utility companies that own nuclear generating units, for a nuclear power plant incident at any nuclear plant in the U.S. Should a nuclear incident occur at any nuclear power plant in the U.S., the liability could be substantial.

Decommissioning and Low Level Waste Accumulation Disposal

The cost to decommission a nuclear plant is affected by NRC regulations and the SNF disposal program. Decommissioning costs are accrued over the service life of the Cook Plant. The most recent decommissioning cost study was performed in 2009. According to that study, the estimated cost of decommissioning and disposal of low-level radioactive waste ranges from $831 million to $1.5 billion in 2009 nondiscounted dollars. The wide range in estimated costs is caused by variables in assumptions. I&M recovers estimated decommissioning costs for the Cook Plant in its rates. The amount recovered in rates was $14 million in 2011, $14 million in 2010 and $16 million in 2009. Reduced annual decommissioning cost recovery amounts reflect the units' longer estimated life and operating licenses granted by the NRC. Decommissioning costs recovered from customers are deposited in external trusts.

At December 31, 2011 and 2010, the total decommissioning trust fund balance was $1.3 billion and $1.2 billion, respectively. Trust fund earnings increase the fund assets and decrease the amount remaining to be recovered from ratepayers. The decommissioning costs (including interest, unrealized gains and losses and expenses of the trust funds) increase or decrease the recorded liability.

I&M continues to work with regulators and customers to recover the remaining estimated costs of decommissioning the Cook Plant. However, future net income, cash flows and possibly financial condition would be adversely affected if the cost of SNF disposal and decommissioning continues to increase and cannot be recovered.

SNF Disposal

The Federal government is responsible for permanent SNF disposal and assesses fees to nuclear plant owners for SNF disposal. A fee of one mill per KWH for fuel consumed after April 6, 1983 at the Cook Plant is being collected from customers and remitted to the U.S. Treasury. At December 31, 2011 and 2010, fees and related interest of $265 million and $265 million, respectively, for fuel consumed prior to April 7, 1983 have been recorded as Long-term Debt and funds collected from customers along with related earnings totaling $308 million and $307 million, respectively, to pay the fee are recorded as part of Spent Nuclear Fuel and Decommissioning Trusts. I&M has not paid the government the pre-April 1983 fees due to continued delays and uncertainties related to the federal disposal program.

In 2011, I&M signed a settlement agreement with the Federal government which permits I&M to make annual filings to recover certain SNF storage costs incurred as a result of the government's delays in accepting SNF for permanent storage. Under the settlement agreement, I&M received $14 million to recover costs and will be eligible to receive additional payment of annual claims for allowed costs that are incurred through December 31, 2013. The proceeds reduced capital costs for dry cask storage.

See "Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal" section of Note 10 for disclosure of the fair value of assets within the trusts.

Nuclear Incident Liability

I&M carries insurance coverage for property damage, decommissioning and decontamination at the Cook Plant in the amount of $1.8 billion. I&M purchases $1 billion of excess coverage for property damage, decommissioning and decontamination. Additional insurance provides coverage for a weekly indemnity payment resulting from an insured accidental outage. I&M utilizes an industry mutual insurer for the placement of this insurance coverage. Participation in this mutual insurance requires a contingent financial obligation of up to $41 million for I&M which is assessable if the insurer's financial resources would be inadequate to pay for losses.

The Price-Anderson Act, extended through December 31, 2025, establishes insurance protection for public liability arising from a nuclear incident at $12.6 billion and covers any incident at a licensed reactor in the U.S. Commercially available insurance, which must be carried for each licensed reactor, provides $375 million of coverage. In the event of a nuclear incident at any nuclear plant in the U.S., the remainder of the liability would be provided by a deferred premium assessment of $117.5 million on each licensed reactor in the U.S. payable in annual installments of $17.5 million. As a result, I&M could be assessed $235 million per nuclear incident payable in annual installments of $35 million. The number of incidents for which payments could be required is not limited.

In the event of an incident of a catastrophic nature, I&M is initially covered for the first $375 million through commercially available insurance. The next level of liability coverage of up to $12.2 billion would be covered by claims made under the Price-Anderson Act. If the liability were in excess of amounts recoverable from insurance and retrospective claim payments made under the Price-Anderson Act, I&M would seek to recover those amounts from customers through rate increases. In the event nuclear losses or liabilities are underinsured or exceed accumulated funds and recovery from customers is not possible, net income, cash flows and financial condition could be adversely affected.

Cook Plant Unit 1 Fire and Shutdown

In September 2008, I&M shut down Cook Plant Unit 1 (Unit 1) due to turbine vibrations, caused by blade failure, which resulted in significant turbine damage and a small fire on the electric generator. This equipment, located in the turbine building, is separate and isolated from the nuclear reactor. The turbine rotors that caused the vibration were installed in 2006 and are within the vendor's warranty period. The warranty provides for the repair or replacement of the turbine rotors if the damage was caused by a defect in materials or workmanship. Repair of the property damage and replacement of the turbine rotors and other equipment cost approximately $400 million. Management believes that I&M should recover a significant portion of these costs through the turbine vendor's warranty, insurance and the regulatory process. Due to the extensive lead time required to manufacture and install new turbine rotors, I&M repaired Unit 1 and it resumed operations in December 2009 at slightly reduced power. The installation of the new turbine rotors and other equipment occurred as planned during the fall 2011 refueling outage of Unit 1.

I&M maintains insurance through NEIL. As of December 31, 2011, we recorded $64 million in Prepayments and Other Current Assets on our balance sheets representing amounts due from NEIL under the insurance policies. Through December 31, 2011, I&M received partial payments of $203 million from NEIL for the cost incurred to date to repair the property damage.

I&M also maintains a separate accidental outage policy with NEIL. In 2009, I&M recorded $185 million in revenue under the policy and reduced the cost of replacement power in customers' bills by $78 million.

NEIL is reviewing claims made under the insurance policies to ensure that claims associated with the outage are covered by the policies. The review by NEIL includes the timing of the unit's return to service and whether the return should have occurred earlier reducing the amount received under the accidental outage policy. If the ultimate costs of the incident are not covered by warranty, insurance or through the regulatory process or if any future regulatory proceedings are adverse, it could have an adverse impact on net income, cash flows and financial condition.

OPERATIONAL CONTINGENCIES

Insurance and Potential Losses

We maintain insurance coverage normal and customary for an integrated electric utility, subject to various deductibles. Our insurance includes coverage for all risks of physical loss or damage to our nonnuclear assets, subject to insurance policy conditions and exclusions. Covered property generally includes power plants, substations, facilities and inventories. Excluded property generally includes transmission and distribution lines, poles and towers. Our insurance programs also generally provide coverage against loss arising from certain claims made by third parties and are in excess of retentions absorbed by us. Coverage is generally provided by a combination of our protected cell of EIS and/or various industry mutual and/or commercial insurance carriers.

See "Nuclear Contingencies" section of this footnote for a discussion of nuclear exposures and related insurance.

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

Fort Wayne Lease

Since 1975, I&M has leased certain energy delivery assets from the City of Fort Wayne, Indiana under a long-term lease that expired on February 28, 2010. I&M negotiated with Fort Wayne to purchase the assets at the end of the lease and reached an agreement (subject to IURC approval) in 2010. The agreement required I&M to purchase the remaining leased property and settled claims Fort Wayne asserted. The agreement provided that I&M pay Fort Wayne a total of $39 million, including interest, over 15 years and Fort Wayne recognized that I&M is the exclusive electricity supplier in the Fort Wayne area. In August 2011, the IURC approved a settlement agreement with the Indiana Office of Utility Consumer Counselor. The transaction is final.

Enron Bankruptcy

In 2001, we purchased Houston Pipeline Company (HPL) from Enron. Various HPL-related contingencies and indemnities from Enron remained unsettled at the date of Enron's bankruptcy. In connection with our acquisition of HPL, we entered into an agreement with BAM Lease Company, which granted HPL the exclusive right to use approximately 55 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, BOA and certain other banks (the BOA Syndicate) and Enron entered into an agreement granting HPL the exclusive use of the cushion gas. Also at the time of our acquisition, Enron and the BOA Syndicate released HPL from all prior and future liabilities and obligations in connection with the financing arrangement. After the Enron bankruptcy, the BOA Syndicate informed HPL of a purported default by Enron under the terms of the financing arrangement. This dispute was litigated in the Enron bankruptcy proceedings and in federal courts in Texas and New York.

In 2007, the judge in the New York action issued a decision on all claims, including those that were pending trial in Texas, granting BOA summary judgment and dismissing our claims. In August 2008, the New York court entered a final judgment of $346 million. In May 2009, the judge awarded $20 million of attorneys' fees to BOA. We appealed these awards. In October 2010, the Court of Appeals affirmed the New York district court's decision as to the final judgment of $346 million plus interest and reversed the New York district court decision as to the judgment dismissing our claims against BOA in the Southern District of Texas.

In 2005, we sold our interest in HPL for approximately $1 billion. Although the assets were legally transferred, we were unable to determine all costs associated with the transfer until the BOA litigation was resolved. We indemnified the buyer of HPL against any damages up to the purchase price resulting from the BOA litigation, including the right to use the 55 BCF of natural gas through 2031. As a result, we deferred the entire gain related to the sale of HPL (approximately $380 million) pending resolution of the Enron and BOA disputes.

The deferred gain related to the sale of HPL, plus accrued interest and attorneys' fees related to the New York court's judgment, was $448 million at December 31, 2010 and was included in Current Liabilities – Deferred Gain and Accrued Litigation Costs on the balance sheet.

In February 2011, we reached a settlement covering all claims with BOA and Enron for $425 million. As part of the settlement, we received title to the 55 BCF of natural gas in the Bammel storage facility and recorded this asset at fair value. Under the HPL sales agreement, we have a service obligation to the buyer for the right to use the cushion gas through May 2031. We recognized the obligation as a liability and will amortize it over the life of the agreement.

The settlement resulted in a pretax gain of $51 million and a net loss after tax of $22 million primarily due to an unrealized capital loss valuation allowance of $56 million.

At the time of the settlement, the following table sets forth its impact on our 2011 financial statements:

		(in millions)
Statement of Income:		
Other Operation Expense - Pretax Gain on Settlement	$	51
Income Tax Expense		73
Net Loss After Tax	$	(22)
Cash Flow Statement:		
Net Income - Loss on Settlement with BOA and Enron	$	(22)
Deferred Income Taxes		91
Gain on Settlement with BOA and Enron		(51)
Settlement of Litigation with BOA and Enron		(211)
Accrued Taxes, Net		(18)
Acquisition of Cushion Gas from BOA		(214)
Cash Paid	$	(425)
Balance Sheet:		
Deferred Charges and Other Noncurrent Assets - Gas Acquired	$	214
Deferred Credits and Other Noncurrent Liabilities - Gas Service Liability		187
Accrued Taxes - Tax Benefit on Settlement with BOA and Enron		18
Deferred Income Taxes - Deferred Tax Benefit on Gas Service Liability		66

Natural Gas Markets Lawsuits

In 2002, the Lieutenant Governor of California filed a lawsuit in Los Angeles County California Superior Court against numerous energy companies, including AEP, alleging violations of California law through alleged fraudulent reporting of false natural gas price and volume information with an intent to affect the market price of natural gas and electricity. AEP was dismissed from the case. A number of similar cases were also filed in California and in state and federal courts in several states making essentially the same allegations under federal or state laws against the same companies. AEP (or a subsidiary) is among the companies named as defendants in some of these cases. In 2008, we settled all of the cases pending against us in California. In July 2011, the judge in the Federal District Court in Las Vegas granted summary judgment dismissing the cases where AEP companies were defendants. Also in July 2011, the plaintiffs in these cases filed notices of appeal to the Ninth Circuit Court of Appeals. We will continue to defend the remaining cases where an AEP company is a defendant, all of which were dismissed by the Federal District Court in Las Vegas and are currently on appeal. We believe the provision we have for the remaining cases is adequate and the remaining exposure is immaterial.

6. ACQUISITIONS, DISPOSITIONS AND IMPAIRMENTS

ACQUISITIONS

Acquisition Anticipated Being Completed During the First Quarter of 2012

BlueStar Energy (Generation and Marketing segment)

In January 2012, we entered into an agreement to acquire BlueStar Energy Holdings, Inc. (BlueStar) and its independent retail electric supplier BlueStar Energy Solutions for approximately $70 million. BlueStar provides electric supply for retail customers in Ohio, Illinois and other deregulated electricity markets and also provides energy solutions, including demand response and energy efficiency services, nationwide. BlueStar has approximately 21,000 customer accounts. Consummation of the transaction is subject to regulatory and other approvals. The transaction is expected to close in the first quarter of 2012.

2010

Valley Electric Membership Corporation (Utility Operations segment)

In October 2010, SWEPCo purchased certain transmission and distribution assets of Valley Electric Membership Corporation (VEMCO) for approximately $102 million and began serving VEMCO's 30,000 customers in Louisiana.

2009

Oxbow Lignite Company and Red River Mining Company (Utility Operations segment)

In December 2009, SWEPCo purchased 50% of the Oxbow Lignite Company, LLC (OLC) membership interest for $13 million. CLECO acquired the remaining 50% membership interest in the OLC for $13 million. The Oxbow Mine is located near Coushatta, Louisiana and is used as one of the fuel sources for SWEPCo's and CLECO's jointly-owned Dolet Hills Generating Station. SWEPCo accounts for OLC as an equity investment. Also, in December 2009, DHLC purchased mining equipment and assets for $16 million from the Red River Mining Company.

DISPOSITIONS

2010

Electric Transmission Texas LLC (ETT) (Utility Operations segment)

In 2010, TCC and TNC sold $66 million and $73 million, respectively, of transmission facilities to ETT. There were no gains or losses recorded on these sale transactions.

Intercontinental Exchange, Inc. (ICE) (All Other)

In April 2010, we sold our remaining 138,000 shares of ICE and recognized a $16 million gain. We recorded the gain in Interest and Investment Income on our statements of income for the year ended December 31, 2010.

2009

Electric Transmission Texas LLC (ETT) (Utility Operations segment)

In 2009, TCC and TNC sold $93 million and $2 million, respectively, of transmission facilities to ETT. There were no gains or losses recorded on these sale transactions.

IMPAIRMENTS

2011

Turk Plant (Utility Operations segment)

In the fourth quarter of 2011, SWEPCo recorded a pretax write-off of $49 million in Asset Impairments and Other Related Charges on the statements of income related to the Texas jurisdictional portion of the Turk Plant as a result of the November 2011 Texas Court of Appeals decision upholding the Texas capital cost cap.

Muskingum River Plant Unit 5 FGD Project (MR5) (Utility Operations segment)

In September 2011, subsequent to the stipulation agreement filed with the PUCO, management determined that OPCo was not likely to complete the previously suspended MR5 project and that the project's preliminary engineering costs were no longer probable of being recovered. As a result, in the third quarter of 2011, OPCo recorded a pretax write-off of $42 million in Asset Impairments and Other Related Charges on the statements of income.

Sporn Plant Unit 5 (Utility Operations segment)

In the third quarter of 2011, management decided to no longer offer the output of Sporn Unit 5 into the PJM market. Sporn Unit 5 is not expected to operate in the future, resulting in the removal of Sporn Unit 5 from the AEP Power Pool. As a result, in the third quarter of 2011, OPCo recorded a pretax write-off of $48 million in Asset Impairments and Other Related Charges on the statements of income.

7. BENEFIT PLANS

For a discussion of investment strategy, investment limitations, target asset allocations and the classification of investments within the fair value hierarchy, see "Investments Held in Trust for Future Liabilities" and "Fair Value Measurements of Assets and Liabilities" sections of Note 1.

We sponsor a qualified pension plan and two unfunded nonqualified pension plans. Substantially all of our employees are covered by the qualified plan or both the qualified and a nonqualified pension plan. We sponsor OPEB plans to provide medical and life insurance benefits for retired employees.

We recognize the funded status associated with our defined benefit pension and OPEB plans in the balance sheets. Disclosures about the plans are required by the "Compensation – Retirement Benefits" accounting guidance. We recognize an asset for a plan's overfunded status or a liability for a plan's underfunded status, and recognize, as a component of other comprehensive income, the changes in the funded status of the plan that arise during the year that are not recognized as a component of net periodic benefit cost. We record a regulatory asset instead of other comprehensive income for qualifying benefit costs of our regulated operations that for ratemaking purposes are deferred for future recovery. The cumulative funded status adjustment is equal to the remaining unrecognized deferrals for unamortized actuarial losses or gains, prior service costs and transition obligations, such that remaining deferred costs result in an AOCI equity reduction or regulatory asset and deferred gains result in an AOCI equity addition or regulatory liability.

Actuarial Assumptions for Benefit Obligations

The weighted-average assumptions as of December 31 of each year used in the measurement of our benefit obligations are shown in the following table:

	Pension Plans		Other Postretirement Benefit Plans	
Assumptions	**2011**	**2010**	**2011**	**2010**
Discount Rate	4.55 %	5.05 %	4.75 %	5.25 %
Rate of Compensation Increase	4.85 % (a)	4.95 % (a)	NA	NA

(a) Rates are for base pay only. In addition, an amount is added to reflect target incentive compensation for exempt employees and overtime and incentive pay for nonexempt employees.
NA Not applicable

We use a duration-based method to determine the discount rate for our plans. A hypothetical portfolio of high quality corporate bonds similar to those included in the Moody's Aa bond index is constructed with a duration matching the benefit plan liability. The composite yield on the hypothetical bond portfolio is used as the discount rate for the plan.

For 2011, the rate of compensation increase assumed varies with the age of the employee, ranging from 3.5% per year to 11.5% per year, with an average increase of 4.85%.

Actuarial Assumptions for Net Periodic Benefit Costs

The weighted-average assumptions as of January 1 of each year used in the measurement of our benefit costs are shown in the following table:

	Pension Plans			Other Postretirement Benefit Plans		
	2011	2010	2009	2011	2010	2009
Discount Rate	5.05 %	5.60 %	6.00 %	5.25 %	5.85 %	6.10 %
Expected Return on Plan Assets	7.75 %	8.00 %	8.00 %	7.50 %	8.00 %	7.75 %
Rate of Compensation Increase	4.85 %	4.60 %	5.90 %	NA	NA	NA

NA Not Applicable

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

The health care trend rate assumptions as of January 1 of each year used for OPEB plans measurement purposes are shown below:

Health Care Trend Rates	2011	2010
Initial	7.50 %	8.00 %
Ultimate	5.00 %	5.00 %
Year Ultimate Reached	2016	2016

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

	1% Increase	1% Decrease
	(in millions)	
Effect on Total Service and Interest Cost Components of Net Periodic Postretirement Health Care Benefit Cost	$ 23	$ (18)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	274	(223)

Significant Concentrations of Risk within Plan Assets

In addition to establishing the target asset allocation of plan assets, the investment policy also places restrictions on securities to limit significant concentrations within plan assets. The investment policy establishes guidelines that govern maximum market exposure, security restrictions, prohibited asset classes, prohibited types of transactions, minimum credit quality, average portfolio credit quality, portfolio duration and concentration limits. The guidelines were established to mitigate the risk of loss due to significant concentrations in any investment. We monitor the plans to control security diversification and ensure compliance with our investment policy. At December 31, 2011, the assets were invested in compliance with all investment limits. See "Investments Held in Trust for Future Liabilities" section of Note 1 for limit details.

Benefit Plan Obligations, Plan Assets and Funded Status as of December 31, 2011 and 2010

The following tables provide a reconciliation of the changes in the plans' benefit obligations, fair value of plan assets and funded status as of December 31. The benefit obligation for the defined benefit pension and OPEB plans are the projected benefit obligation and the accumulated benefit obligation, respectively.

	Pension Plans		Other Postretirement Benefit Plans	
	2011	2010	2011	2010
Change in Benefit Obligation	(in millions)			
Benefit Obligation at January 1	$ 4,807	$ 4,701	$ 2,125	$ 1,941
Service Cost	72	111	42	47
Interest Cost	237	253	109	113
Actuarial Loss	169	222	253	164
Plan Amendment Prior Service Credit	-	-	(196)	(36)
Curtailment	-	-	1	-
Benefit Payments	(294)	(480)	(150)	(142)
Participant Contributions	-	-	34	29
Medicare Subsidy	-	-	9	9
Benefit Obligation at December 31	$ 4,991	$ 4,807	$ 2,227	$ 2,125
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets at January 1	$ 3,858	$ 3,403	$ 1,461	$ 1,308
Actual Gain (Loss) on Plan Assets	282	420	(14)	149
Company Contributions	457	515	79	117
Participant Contributions	-	-	34	29
Benefit Payments	(294)	(480)	(150)	(142)
Fair Value of Plan Assets at December 31	$ 4,303	$ 3,858	$ 1,410	$ 1,461
Underfunded Status at December 31	$ (688)	$ (949)	$ (817)	$ (664)

Benefit Amounts Recognized on the Balance Sheets as of December 31, 2011 and 2010

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2011	2010	2011	2010
	(in millions)			
Other Current Liabilities - Accrued Short-term Benefit Liability	$ (8)	$ (8)	$ (4)	$ (4)
Employee Benefits and Pension Obligations - Accrued Long-term Benefit Liability	(680)	(941)	(813)	(660)
Underfunded Status	$ (688)	$ (949)	$ (817)	$ (664)

Amounts Included in AOCI and Regulatory Assets as of December 31, 2011 and 2010

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2011	2010	2011	2010
Components	(in millions)			
Net Actuarial Loss	$ 2,208	$ 2,129	$ 979	$ 638
Prior Service Cost (Credit)	10	11	(210)	(20)
Transition Obligation	-	-	1	3
Recorded as				
Regulatory Assets	$ 1,818	$ 1,764	$ 479	$ 388
Deferred Income Taxes	140	132	102	81
Net of Tax AOCI	260	244	189	152

Components of the change in amounts included in AOCI and Regulatory Assets during the years ended December 31, 2011 and 2010 are as follows:

	Pension Plans		Other Postretirement Benefit Plans	
	Years Ended December 31,			
	2011	2010	2011	2010
Components	(in millions)			
Actuarial Loss During the Year	$ 201	$ 121	$ 370	$ 121
Prior Service Credit	-	-	(191)	(36)
Amortization of Actuarial Loss	(122)	(89)	(29)	(29)
Amortization of Prior Service Credit (Cost)	(1)	-	1	-
Amortization of Transition Obligation	-	-	(2)	(27)
Change for the Year	$ 78	$ 32	$ 149	$ 29

Pension and Other Postretirement Plans' Assets

The following table presents the classification of pension plan assets within the fair value hierarchy at December 31, 2011:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 1,455	$ -	$ -	$ -	$ 1,455	33.8 %
International	399	-	-	-	399	9.3 %
Real Estate Investment Trusts	104	-	-	-	104	2.4 %
Common Collective Trust - International	-	128	-	-	128	3.0 %
Subtotal - Equities	1,958	128	-	-	2,086	48.5 %
Fixed Income:						
Common Collective Trust - Debt	-	26	-	-	26	0.6 %
United States Government and Agency Securities	-	566	-	-	566	13.2 %
Corporate Debt	-	985	6	-	991	23.0 %
Foreign Debt	-	190	-	-	190	4.4 %
State and Local Government	-	48	-	-	48	1.1 %
Other - Asset Backed	-	26	-	-	26	0.6 %
Subtotal - Fixed Income	-	1,841	6	-	1,847	42.9 %
Real Estate	-	-	163	-	163	3.8 %
Alternative Investments	-	-	161	-	161	3.7 %
Securities Lending	-	215	-	-	215	5.0 %
Securities Lending Collateral (a)	-	-	-	(236)	(236)	(5.5)%
Cash and Cash Equivalents	-	93	-	-	93	2.2 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	(26)	(26)	(0.6)%
Total	$ 1,958	$ 2,277	$ 330	$ (262)	$ 4,303	100.0 %

(a) Amounts in "Other" column primarily represent an obligation to repay cash collateral received as part of the Securities Lending Program.
(b) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

The following table sets forth a reconciliation of changes in the fair value of assets classified as Level 3 in the fair value hierarchy for AEP's pension assets:

	Corporate Debt	Real Estate	Alternative Investments	Total Level 3
		(in millions)		
Balance as of January 1, 2011	$ -	$ 83	$ 130	$ 213
Actual Return on Plan Assets				
Relating to Assets Still Held as of the Reporting Date	-	22	9	31
Relating to Assets Sold During the Period	-	-	3	3
Purchases and Sales	-	58	19	77
Transfers into Level 3	6	-	-	6
Transfers out of Level 3	-	-	-	-
Balance as of December 31, 2011	$ 6	$ 163	$ 161	$ 330

The following table presents the classification of OPEB plan assets within the fair value hierarchy at December 31, 2011:

Asset Class	Level 1	Level 2	Level 3 (in millions)	Other	Total	Year End Allocation
Equities:						
Domestic	$ 348	$ -	$ -	$ -	$ 348	24.7 %
International	380	-	-	-	380	27.0 %
Common Collective Trust - Global	-	99	-	-	99	7.0 %
Subtotal - Equities	728	99	-	-	827	58.7 %
Fixed Income:						
Common Collective Trust - Debt	-	69	-	-	69	4.9 %
United States Government and Agency Securities	-	81	-	-	81	5.7 %
Corporate Debt	-	152	-	-	152	10.8 %
Foreign Debt	-	32	-	-	32	2.3 %
State and Local Government	-	9	-	-	9	0.6 %
Other - Asset Backed	-	2	-	-	2	0.1 %
Subtotal - Fixed Income	-	345	-	-	345	24.4 %
Trust Owned Life Insurance:						
International Equities	-	46	-	-	46	3.3 %
United States Bonds	-	158	-	-	158	11.2 %
Cash and Cash Equivalents	17	23	-	-	40	2.9 %
Other - Pending Transactions and Accrued Income (a)	-	-	-	(6)	(6)	(0.5)%
Total	$ 745	$ 671	$ -	$ (6)	$ 1,410	100.0 %

(a) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

The following table presents the classification of pension plan assets within the fair value hierarchy at December 31, 2010:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 1,350	$ 2	$ -	$ -	$ 1,352	35.1 %
International	403	-	-	-	403	10.4 %
Real Estate Investment Trusts	112	-	-	-	112	2.9 %
Common Collective Trust - International	-	163	-	-	163	4.2 %
Subtotal - Equities	1,865	165	-	-	2,030	52.6 %
Fixed Income:						
United States Government and Agency Securities	-	634	-	-	634	16.4 %
Corporate Debt	-	672	-	-	672	17.4 %
Foreign Debt	-	127	-	-	127	3.3 %
State and Local Government	-	23	-	-	23	0.6 %
Other - Asset Backed	-	51	-	-	51	1.3 %
Subtotal - Fixed Income	-	1,507	-	-	1,507	39.0 %
Real Estate	-	-	83	-	83	2.2 %
Alternative Investments	-	-	130	-	130	3.4 %
Securities Lending	-	254	-	-	254	6.6 %
Securities Lending Collateral (a)	-	-	-	(276)	(276)	(7.1)%
Cash and Cash Equivalents (b)	-	127	-	2	129	3.3 %
Other - Pending Transactions and Accrued Income (c)	-	-	-	1	1	- %
Total	$ 1,865	$ 2,053	$ 213	$ (273)	$ 3,858	100.0 %

(a) Amounts in "Other" column primarily represent an obligation to repay cash collateral received as part of the Securities Lending Program.
(b) Amounts in "Other" column primarily represent foreign currency holdings.
(c) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

The following table sets forth a reconciliation of changes in the fair value of real estate and alternative investments classified as Level 3 in the fair value hierarchy for the pension assets:

	Real Estate	Alternative Investments	Total Level 3
		(in millions)	
Balance as of January 1, 2010	$ 90	$ 106	$ 196
Actual Return on Plan Assets			
Relating to Assets Still Held as of the Reporting Date	(7)	4	(3)
Relating to Assets Sold During the Period	-	1	1
Purchases and Sales	-	19	19
Transfers into Level 3	-	-	-
Transfers out of Level 3	-	-	-
Balance as of December 31, 2010	$ 83	$ 130	$ 213

The following table presents the classification of OPEB plan assets within the fair value hierarchy at December 31, 2010:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 584	$ -	$ -	$ -	$ 584	40.0 %
International	220	-	-	-	220	15.1 %
Common Collective Trust - Global	-	115	-	-	115	7.9 %
Subtotal - Equities	804	115	-	-	919	63.0 %
Fixed Income:						
Common Collective Trust - Debt	-	48	-	-	48	3.3 %
United States Government and Agency Securities	-	93	-	-	93	6.4 %
Corporate Debt	-	110	-	-	110	7.5 %
Foreign Debt	-	25	-	-	25	1.7 %
State and Local Government	-	3	-	-	3	0.2 %
Other - Asset Backed	-	1	-	-	1	0.1 %
Subtotal - Fixed Income	-	280	-	-	280	19.2 %
Trust Owned Life Insurance:						
International Equities	-	49	-	-	49	3.3 %
United States Bonds	-	163	-	-	163	11.1 %
Cash and Cash Equivalents (a)	21	25	-	1	47	3.2 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	3	3	0.2 %
Total	$ 825	$ 632	$ -	$ 4	$ 1,461	100.0 %

(a) Amounts in "Other" column primarily represent foreign currency holdings.
(b) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

Determination of Pension Expense

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

Accumulated Benefit Obligation	December 31, 2011	December 31, 2010
	(in millions)	
Qualified Pension Plan	$ 4,808	$ 4,659
Nonqualified Pension Plans	89	80
Total	$ 4,897	$ 4,739

For our underfunded pension plans that had an accumulated benefit obligation in excess of plan assets, the projected benefit obligation, accumulated benefit obligation and fair value of plan assets of these plans at December 31, 2011 and 2010 were as follows:

	Underfunded Pension Plans December 31, 2011	Underfunded Pension Plans December 31, 2010
	(In millions)	
Projected Benefit Obligation	$ 4,991	$ 4,807
Accumulated Benefit Obligation	$ 4,897	$ 4,739
Fair Value of Plan Assets	4,303	3,858
Underfunded Accumulated Benefit Obligation	$ (594)	$ (881)

Estimated Future Benefit Payments and Contributions

We expect contributions and payments for the pension plans of $208 million and the OPEB plans of $99 million during 2012. The estimated pension benefit payments for the unfunded plan and contributions to the trust are at least the minimum amount required by the Employee Retirement Income Security Act plus payment of unfunded nonqualified benefits. For the qualified pension plan, we may make additional discretionary contributions to maintain the funded status of the plan. The contribution to the OPEB plans is generally based on the amount of the OPEB plans' periodic benefit costs for accounting purposes as provided in agreements with state regulatory authorities, plus the additional discretionary contribution of our Medicare subsidy receipts.

The table below reflects the total benefits expected to be paid from the plan or from our assets. The payments include the participants' contributions to the plan for their share of the cost. In December 2011, we amended the prescription drug program for certain participants. The impact of the change is reflected in the Benefit Plan Obligation table as a plan amendment. As a result of this amendment to the plan, the Medicare subsidy receipts in the following table are reduced from prior published estimates. Future benefit payments are dependent on the number of employees retiring, whether the retiring employees elect to receive pension benefits as annuities or as lump sum distributions, future integration of the benefit plans with changes to Medicare and other legislation, future levels of interest rates and variances in actuarial results. The estimated payments for pension benefits and OPEB are as follows:

	Pension Plans	Other Postretirement Benefit Plans	
	Pension Payments	Benefit Payments	Medicare Subsidy Receipts
		(in millions)	
2012	$ 327	$ 145	$ 9
2013	334	148	-
2014	354	153	-
2015	356	160	-
2016	360	168	-
Years 2017 to 2021, in Total	1,864	955	2

Components of Net Periodic Benefit Cost

The following table provides the components of our net periodic benefit cost for the plans for the years ended December 31, 2011, 2010 and 2009:

	Pension Plans			Other Postretirement Benefit Plans		
	Years Ended December 31,					
	2011	2010	2009	2011	2010	2009
	(in millions)					
Service Cost	$ 72	$ 111	$ 104	$ 42	$ 47	$ 42
Interest Cost	237	253	254	109	113	110
Expected Return on Plan Assets	(314)	(312)	(321)	(109)	(105)	(80)
Curtailment	-	-	-	1	-	-
Amortization of Transition Obligation	-	-	-	2	27	27
Amortization of Prior Service Cost (Credit)	1	-	-	(1)	-	-
Amortization of Net Actuarial Loss	122	89	59	29	29	42
Net Periodic Benefit Cost	118	141	96	73	111	141
Capitalized Portion	(37)	(44)	(30)	(22)	(35)	(44)
Net Periodic Benefit Cost Recognized as Expense	$ 81	$ 97	$ 66	$ 51	$ 76	$ 97

Estimated amounts expected to be amortized to net periodic benefit costs and the impact on the balance sheet during 2012 are shown in the following table:

Components	Pension Plans	Other Postretirement Benefit Plans
	(in millions)	
Net Actuarial Loss	$ 145	$ 59
Prior Service Credit	(1)	(18)
Transition Obligation	-	1
Total Estimated 2012 Amortization	$ 144	$ 42
Expected to be Recorded as		
Regulatory Asset	$ 116	$ 25
Deferred Income Taxes	10	6
Net of Tax AOCI	18	11
Total	$ 144	$ 42

American Electric Power System Retirement Savings Plan

We sponsor the American Electric Power System Retirement Savings Plan, a defined contribution retirement savings plan for substantially all employees who are not members of the United Mine Workers of America (UMWA). It is a qualified plan offering participants an opportunity to contribute a portion of their pay with features under Section 401(k) of the Internal Revenue Code. The matching contributions to the plan are 100% of the first 1% of eligible employee contributions and 70% of the next 5% of contributions. The cost for matching contributions totaled $64 million in 2011, $61 million in 2010 and $74 million in 2009.

UMWA Benefits

We provide UMWA pension, health and welfare benefits for certain unionized mining employees, retirees and their survivors who meet eligibility requirements. UMWA trustees make final interpretive determinations with regard to all benefits. The pension benefits are administered by UMWA trustees and contributions are made to their trust funds. The health and welfare benefits are administered by us and benefits are paid from our general assets.

The UMWA pension benefits are administered through a multiemployer plan that is different from single-employer plans as an employer's contributions may be used to provide benefits to employees of other participating employers. Required contributions not made by an employer may result in other employers bearing the unfunded plan obligations, while a withdrawing employer may be subject to a withdrawal liability. UMWA pension benefits are provided through the United Mine Workers of America 1974 Pension Plan (Employer Identification Number: 52-1050282, Plan Number 002), which under the Pension Protection Act of 2006 (PPA) was in Seriously Endangered Status for the plan years ending June 30, 2011 and 2010, without utilization of extended amortization provisions. The Plan is required under the PPA to adopt a funding improvement plan by May 25, 2012. Contributions in 2011, 2010 and 2009, which were made under a collective bargaining agreement that expires December 31, 2012, were immaterial and represent less than 5% of the total contributions in the plan's latest annual report for the years ended June 30, 2011, 2010 and 2009. Contributions did not include a surcharge, and there are no minimum contributions for future years.

8. BUSINESS SEGMENTS

Our primary business is the generation, transmission and distribution of electricity. Within our Utility Operations segment, we centrally dispatch generation assets and manage our overall utility operations on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight. Intersegment sales and transfers are generally based on underlying contractual arrangements and agreements.

While our Utility Operations segment remains our primary business segment, the advancement of an area of our business prompted us to identify a new reportable segment. Starting in the fourth quarter of 2011, we established our new Transmission Operations segment as described below:

Utility Operations

- Generation of electricity for sale to U.S. retail and wholesale customers.
- Transmission and distribution of electricity through assets owned and operated by our ten utility operating companies.

Transmission Operations

- Development, construction and operation of transmission facilities through investments in our wholly-owned transmission subsidiaries that were established in 2009 and our transmission joint ventures. These investments have FERC-approved returns on equity.

AEP River Operations

- Commercial barging operations that transport coal and dry bulk commodities primarily on the Ohio, Illinois and lower Mississippi Rivers.

Generation and Marketing

- Nonregulated generation in ERCOT.
- Marketing and risk management activities primarily in ERCOT and, to a lesser extent, Ohio in PJM and MISO.

The remainder of our activities is presented as All Other. While not considered a reportable segment, All Other includes:

- Parent's guarantee revenue received from affiliates, investment income, interest income and interest expense and other nonallocated costs.
- Tax and interest expense adjustments related to our UK operations which were sold in 2004 and 2002.
- Forward natural gas contracts that were not sold with our natural gas pipeline and storage operations in 2004 and 2005. These contracts were financial derivatives which settled and expired in the fourth quarter of 2011.
- Revenue sharing related to the Plaquemine Cogeneration Facility which ended in the fourth quarter of 2011.

The tables below present our reportable segment information for the years ended December 31, 2011, 2010 and 2009 and balance sheet information as of December 31, 2011 and 2010. These amounts include certain estimates and allocations where necessary. We reclassified prior year amounts to conform to the current year's presentation.

		Nonutility Operations					
	Utility Operations	Transmission Operations	AEP River Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
				(in millions)			
Year Ended December 31, 2011							
Revenues from:							
External Customers	$ 14,088	$ 3	$ 696	$ 305	$ 24	$ -	$ 15,116
Other Operating Segments	112	5	20	1	8	(146)	-
Total Revenues	$ 14,200	$ 8	$ 716	$ 306	$ 32	$ (146)	$ 15,116
Depreciation and Amortization	$ 1,613	$ -	$ 28	$ 25	$ 2	$ (13)(b)	$ 1,655
Interest Income	29	-	-	(1)	17	(18)	27
Carrying Costs Income	393	-	-	-	-	-	393
Interest Expense	886	1	18	18	43	(33)(b)	933
Income Tax Expense (Credit)	722	2	24	(18)	88	-	818
Income (Loss) Before Extraordinary Items	$ 1,549	$ 30	$ 45	$ 14	$ (62)	$ -	$ 1,576
Extraordinary Items, Net of Tax	373	-	-	-	-	-	373
Net Income (Loss)	$ 1,922	$ 30	$ 45	$ 14	$ (62)	$ -	$ 1,949
Gross Property Additions	$ 2,405	$ 263	$ 18	$ 2	$ 214	$ -	$ 2,902

		Nonutility Operations					
	Utility Operations	Transmission Operations	AEP River Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
				(in millions)			
Year Ended December 31, 2010							
Revenues from:							
External Customers	$ 13,687	$ -	$ 566	$ 173	$ 1	$ -	$ 14,427
Other Operating Segments	105	1	22	-	14	(142)	-
Total Revenues	$ 13,792	$ 1	$ 588	$ 173	$ 15	$ (142)	$ 14,427
Depreciation and Amortization	$ 1,598	$ -	$ 24	$ 30	$ 2	$ (13)(b)	$ 1,641
Interest Income	8	-	-	2	31	(20)	21
Carrying Costs Income	70	-	-	-	-	-	70
Interest Expense	942	-	14	20	58	(35)(b)	999
Income Tax Expense (Credit)	651	(1)	19	(20)	(6)	-	643
Net Income (Loss)	1,192	9	37	25	(45)	-	1,218
Gross Property Additions	2,440	35	23	1	1	-	2,500

	Utility Operations	Transmission Operations	Nonutility Operations: AEP River Operations	Nonutility Operations: Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
				(in millions)			
Year Ended December 31, 2009							
Revenues from:							
External Customers	$ 12,733 (d)	$ -	$ 490	$ 281	$ (15)	$ -	$ 13,489
Other Operating Segments	70 (d)	-	18	5	36	(129)	-
Total Revenues	$ 12,803	$ -	$ 508	$ 286	$ 21	$ (129)	$ 13,489
Depreciation and Amortization	$ 1,561	$ -	$ 17	$ 29	$ 2	$ (12)(b)	$ 1,597
Interest Income	4	-	-	-	47	(40)	11
Carrying Costs Income	47	-	-	-	-	-	47
Interest Expense	916	-	5	21	86	(55)(b)	973
Income Tax Expense (Credit)	553	-	23	-	(1)	-	575
Income (Loss) Before Extraordinary Items	$ 1,325	$ 4	$ 47	$ 41	$ (47)	$ -	$ 1,370
Extraordinary Items, Net of Tax	(5)	-	-	-	-	-	(5)
Net Income (Loss)	$ 1,320	$ 4	$ 47	$ 41	$ (47)	$ -	$ 1,365
Gross Property Additions	$ 2,812	$ 1	$ 81	$ 1	$ 1	$ -	$ 2,896

	Utility Operations	Transmission Operations	Nonutility Operations: AEP River Operations	Nonutility Operations: Generation and Marketing	All Other (a)	Reconciling Adjustments (b)	Consolidated
				(in millions)			
December 31, 2011							
Total Property, Plant and Equipment	$ 54,396	$ 323	$ 608	$ 590	$ 11	$ (258)	$ 55,670
Accumulated Depreciation and Amortization	18,393	-	136	219	10	(59)	18,699
Total Property, Plant and Equipment - Net	$ 36,003	$ 323	$ 472	$ 371	$ 1	$ (199)	$ 36,971
Total Assets	$ 50,093	$ 594	$ 659	$ 868	$ 16,751	$ (16,742) (c)	$ 52,223
Investments in Equity Method Investees	24	256	17	-	2	-	299

	Utility Operations	Transmission Operations	Nonutility Operations: AEP River Operations	Nonutility Operations: Generation and Marketing	All Other (a)	Reconciling Adjustments (b)	Consolidated
				(in millions)			
December 31, 2010							
Total Property, Plant and Equipment	$ 52,771	$ 51	$ 574	$ 584	$ 11	$ (251)	$ 53,740
Accumulated Depreciation and Amortization	17,795	-	110	198	9	(46)	18,066
Total Property, Plant and Equipment - Net	$ 34,976	$ 51	$ 464	$ 386	$ 2	$ (205)	$ 35,674
Total Assets	$ 48,658	$ 230	$ 621	$ 881	$ 15,942	$ (15,877) (c)	$ 50,455
Investments in Equity Method Investees	22	135	3	-	-	-	160

(a) All Other includes:
- Parent's guarantee revenue received from affiliates, investment income, interest income and interest expense and other nonallocated costs.
- Tax and interest expense adjustments related to our UK operations which were sold in 2004 and 2002.
- Forward natural gas contracts that were not sold with our natural gas pipeline and storage operations in 2004 and 2005. These contracts were financial derivatives which settled and expired in the fourth quarter of 2011.
- Revenue sharing related to the Plaquemine Cogeneration Facility which ended in the fourth quarter of 2011.

(b) Includes eliminations due to an intercompany capital lease.

(c) 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.

(d) PSO and SWEPCo transferred certain existing ERCOT energy marketing contracts to AEP Energy Partners, Inc. (AEPEP) (Generation and Marketing segment) and entered into intercompany financial and physical purchase and sales agreements with AEPEP. As a result, we reported third-party net purchases or sales activity for these energy marketing contracts as Revenues from External Customers for the Utility Operations segment. This was offset by the Utility Operations segment's related net purchases for these contracts with AEPEP in Revenues from Other Operating Segments of $5 million for the years ended December 31, 2009. The Generation and Marketing segment also reported these purchase or sales contracts with Utility Operations as Revenues from Other Operating Segments. These affiliated contracts between PSO and SWEPCo with AEPEP ended in December 2009.

9. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

We are exposed to certain market risks as a major power producer and marketer of wholesale electricity, coal and emission allowances. These risks include commodity price risk, interest rate risk, credit risk and, to a lesser extent, foreign currency exchange risk. These risks represent the risk of loss that may impact us due to changes in the underlying market prices or rates. We manage these risks using derivative instruments.

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Trading Strategies

Our strategy surrounding the use of derivative instruments for trading purposes focuses on seizing market opportunities to create value driven by expected changes in the market prices of the commodities in which we transact.

Risk Management Strategies

Our strategy surrounding the use of derivative instruments focuses on managing our risk exposures, future cash flows and creating value utilizing both economic and formal hedging strategies. To accomplish our objectives, we primarily employ risk management contracts including physical forward purchase and sale contracts, financial forward purchase and sale contracts and financial swap instruments. Not all risk management contracts meet the definition of a derivative under the accounting guidance for "Derivatives and Hedging." Derivative risk management contracts elected normal under the normal purchases and normal sales scope exception are not subject to the requirements of this accounting guidance.

We enter into power, coal, natural gas, interest rate and, to a lesser degree, heating oil and gasoline, emission allowance and other commodity contracts to manage the risk associated with our energy business. We enter into interest rate derivative contracts in order to manage the interest rate exposure associated with our commodity portfolio. For disclosure purposes, such risks are grouped as "Commodity," as they are related to energy risk management activities. We also engage in risk management of interest rate risk associated with debt financing and foreign currency risk associated with future purchase obligations denominated in foreign currencies. For disclosure purposes, these risks are grouped as "Interest Rate and Foreign Currency." The amount of risk taken is determined by the Commercial Operations and Finance groups in accordance with our established risk management policies as approved by the Finance Committee of our Board of Directors.

The following table represents the gross notional volume of our outstanding derivative contracts as of December 31, 2011 and 2010:

Notional Volume of Derivative Instruments

Primary Risk Exposure	Volume December 31, 2011	Volume December 31, 2010	Unit of Measure
	(in millions)		
Commodity:			
Power	609	652	MWHs
Coal	21	63	Tons
Natural Gas	100	94	MMBtus
Heating Oil and Gasoline	6	6	Gallons
Interest Rate	$ 226	$ 171	USD
Interest Rate and Foreign Currency	$ 907	$ 907	USD

Fair Value Hedging Strategies

We enter into interest rate derivative transactions as part of an overall strategy to manage the mix of fixed-rate and floating-rate debt. Certain interest rate derivative transactions effectively modify our exposure to interest rate risk by converting a portion of our fixed-rate debt to a floating rate. Provided specific criteria are met, these interest rate derivatives are designated as fair value hedges.

Cash Flow Hedging Strategies

We enter into and designate as cash flow hedges certain derivative transactions for the purchase and sale of power, coal, natural gas and heating oil and gasoline ("Commodity") in order to manage the variable price risk related to the forecasted purchase and sale of these commodities. We monitor the potential impacts of commodity price changes and, where appropriate, enter into derivative transactions to protect profit margins for a portion of future electricity sales and fuel or energy purchases. We do not hedge all commodity price risk.

Our vehicle fleet and barge operations are exposed to gasoline and diesel fuel price volatility. We enter into financial heating oil and gasoline derivative contracts in order to mitigate price risk of our future fuel purchases. For disclosure purposes, these contracts are included with other hedging activities as "Commodity." We do not hedge all fuel price risk.

We enter into a variety of interest rate derivative transactions in order to manage interest rate risk exposure. Some interest rate derivative transactions effectively modify our exposure to interest rate risk by converting a portion of our floating-rate debt to a fixed rate. We also enter into interest rate derivative contracts to manage interest rate exposure related to future borrowings of fixed-rate debt. Our forecasted fixed-rate debt offerings have a high probability of occurrence as the proceeds will be used to fund existing debt maturities and projected capital expenditures. We do not hedge all interest rate exposure.

At times, we are exposed to foreign currency exchange rate risks primarily when we purchase certain fixed assets from foreign suppliers. In accordance with our risk management policy, we may enter into foreign currency derivative transactions to protect against the risk of increased cash outflows resulting from a foreign currency's appreciation against the dollar. We do not hedge all foreign currency exposure.

ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND THE IMPACT ON OUR FINANCIAL STATEMENTS

The accounting guidance for "Derivatives and Hedging" requires recognition of all qualifying derivative instruments as either assets or liabilities on the balance sheets at fair value. The fair values of derivative instruments accounted for using MTM accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data and assumptions. In order to determine the relevant fair values of our derivative instruments, we also apply valuation adjustments for discounting, liquidity and credit quality.

Credit risk is the risk that a counterparty will fail to perform on the contract or fail to pay amounts due. Liquidity risk represents the risk that imperfections in the market will cause the price to vary from estimated fair value based upon prevailing market supply and demand conditions. Since energy markets are imperfect and volatile, there are inherent risks related to the underlying assumptions in models used to fair value risk management contracts. Unforeseen events may cause reasonable price curves to differ from actual price curves throughout a contract's term and at the time a contract settles. Consequently, there could be significant adverse or favorable effects on future net income and cash flows if market prices are not consistent with our estimates of current market consensus for forward prices in the current period. This is particularly true for longer term contracts. Cash flows may vary based on market conditions, margin requirements and the timing of settlement of our risk management contracts.

According to the accounting guidance for "Derivatives and Hedging," we reflect the fair values of our derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, we are required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the December 31, 2011 and 2010 balance sheets, we netted $26 million and $8 million, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and $133 million and $109 million, respectively, of cash collateral paid to third parties against short-term and long-term risk management liabilities.

The following tables represent the gross fair value impact of our derivative activity on our balance sheets as of December 31, 2011 and 2010:

Fair Value of Derivative Instruments
December 31, 2011

	Risk Management Contracts	Hedging Contracts			
Balance Sheet Location	**Commodity (a)**	**Commodity (a)**	**Interest Rate and Foreign Currency (a)**	**Other (b)**	**Total**
		(in millions)			
Current Risk Management Assets	$ 852	$ 24	$ -	$ (683)	$ 193
Long-term Risk Management Assets	641	15	-	(253)	403
Total Assets	1,493	39	-	(936)	596
Current Risk Management Liabilities	847	29	20	(746)	150
Long-term Risk Management Liabilities	483	15	22	(325)	195
Total Liabilities	1,330	44	42	(1,071)	345
Total MTM Derivative Contract Net Assets (Liabilities)	$ 163	$ (5)	$ (42)	$ 135	$ 251

Fair Value of Derivative Instruments
December 31, 2010

	Risk Management Contracts	Hedging Contracts			
Balance Sheet Location	**Commodity (a)**	**Commodity (a)**	**Interest Rate and Foreign Currency (a)**	**Other (b)**	**Total**
		(in millions)			
Current Risk Management Assets	$ 1,023	$ 18	$ 30	$ (839)	$ 232
Long-term Risk Management Assets	546	12	2	(150)	410
Total Assets	1,569	30	32	(989)	642
Current Risk Management Liabilities	995	13	2	(881)	129
Long-term Risk Management Liabilities	387	6	3	(255)	141
Total Liabilities	1,382	19	5	(1,136)	270
Total MTM Derivative Contract Net Assets (Liabilities)	$ 187	$ 11	$ 27	$ 147	$ 372

(a) Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented on the balance sheets on a net basis in accordance with the accounting guidance for "Derivatives and Hedging."
(b) Amounts include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging." Amounts also include de-designated risk management contracts.

The table below presents our activity of derivative risk management contracts for the years ended December 31, 2011, 2010 and 2009:

Amount of Gain (Loss) Recognized on Risk Management Contracts

Location of Gain (Loss)	Years Ended December 31, 2011	2010	2009
	(in millions)		
Utility Operations Revenues	$ 46	$ 85	$ 144
Other Revenues	20	9	19
Regulatory Assets (a)	(22)	(9)	(28)
Regulatory Liabilities (a)	(3)	38	(7)
Total Gain (Loss) on Risk Management Contracts	$ 41	$ 123	$ 128

(a) Represents realized and unrealized gains and losses subject to regulatory accounting treatment recorded as either current or noncurrent on the balance sheets.

Certain qualifying derivative instruments have been designated as normal purchase or normal sale contracts, as provided in the accounting guidance for "Derivatives and Hedging." Derivative contracts that have been designated as normal purchases or normal sales under that accounting guidance are not subject to MTM accounting treatment and are recognized on the statements of income on an accrual basis.

Our accounting for the changes in the fair value of a derivative instrument depends on whether it qualifies for and has been designated as part of a hedging relationship and further, on the type of hedging relationship. Depending on the exposure, we designate a hedging instrument as a fair value hedge or a cash flow hedge.

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in Revenues on a net basis on the statements of income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in Revenues or Expenses on the statements of income depending on the relevant facts and circumstances. However, unrealized and some realized gains and losses in regulated jurisdictions for both trading and non-trading derivative instruments are recorded as regulatory assets (for losses) or regulatory liabilities (for gains) in accordance with the accounting guidance for "Regulated Operations."

Accounting for Fair Value Hedging Strategies

For fair value hedges (i.e. hedging the exposure to changes in the fair value of an asset, liability or an identified portion thereof attributable to a particular risk), the gain or loss on the derivative instrument as well as the offsetting gain or loss on the hedged item associated with the hedged risk impacts Net Income during the period of change.

We record realized and unrealized gains or losses on interest rate swaps that qualify for fair value hedge accounting treatment and any offsetting changes in the fair value of the debt being hedged in Interest Expense on our statements of income. During 2011 and 2010, we recognized gains of $3 million and $6 million, respectively, on our hedging instruments and offsetting losses of $6 million and $6 million, respectively, on our long-term debt. For 2011 and 2010, hedge ineffectiveness was immaterial. During 2009, we did not employ any fair value hedging strategies.

Accounting for Cash Flow Hedging Strategies

For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows attributable to a particular risk), we initially report the effective portion of the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income (Loss) on our balance sheets until the period the hedged item affects Net Income. We recognize any hedge ineffectiveness in Net Income immediately during the period of change, except in regulated jurisdictions where hedge ineffectiveness is recorded as a regulatory asset (for losses) or a regulatory liability (for gains).

Realized gains and losses on derivative contracts for the purchase and sale of power, coal, natural gas, and heating oil and gasoline designated as cash flow hedges are included in Revenues, Fuel and Other Consumables Used for Electric Generation or Purchased Electricity for Resale on our statements of income or in Regulatory Assets or Regulatory Liabilities on our balance sheets, depending on the specific nature of the risk being hedged. During 2011, 2010 and 2009, we designated commodity derivatives as cash flow hedges.

We reclassify gains and losses on financial fuel derivative contracts designated as cash flow hedges from Accumulated Other Comprehensive Income (Loss) on our balance sheets into Other Operation expense, Maintenance expense or Depreciation and Amortization expense, as it relates to capital projects, on our statements of income. During 2011, 2010 and 2009, we designated heating oil and gasoline derivatives as cash flow hedges.

We reclassify gains and losses on interest rate derivative hedges related to our debt financings from Accumulated Other Comprehensive Income (Loss) into Interest Expense in those periods in which hedged interest payments occur. During 2011, 2010 and 2009, we designated interest rate derivatives as cash flow hedges.

The accumulated gains or losses related to our foreign currency hedges are reclassified from Accumulated Other Comprehensive Income (Loss) on our balance sheets into Depreciation and Amortization expense on our statements of income over the depreciable lives of the fixed assets designated as the hedged items in qualifying foreign currency hedging relationships. During 2011, 2010 and 2009, we designated foreign currency derivatives as cash flow hedges.

During 2009, we recognized a $6 million gain in Interest Expense related to hedge ineffectiveness on interest rate derivatives designated in cash flow hedge strategies. During 2011, 2010 and 2009, hedge ineffectiveness was immaterial or nonexistent for all of the other cash flow hedge strategies disclosed above.

The following tables provide details on designated, effective cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on our balance sheets and the reasons for changes in cash flow hedges for the years ended December 31, 2011, 2010 and 2009. All amounts in the following tables are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
Year Ended December 31, 2011

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Balance in AOCI as of December 31, 2010	$ 7	$ 4	$ 11
Changes in Fair Value Recognized in AOCI	(5)	(28)	(33)
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:			
Utility Operations Revenues	3	-	3
Other Revenues	(5)	-	(5)
Purchased Electricity for Resale	(2)	-	(2)
Other Operation Expense	(1)	-	(1)
Maintenance Expense	(1)	-	(1)
Interest Expense	-	4	4
Property, Plant and Equipment	(1)	-	(1)
Regulatory Assets (a)	2	-	2
Regulatory Liabilities (a)	-	-	-
Balance in AOCI as of December 31, 2011	$ (3)	$ (20)	$ (23)

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
Year Ended December 31, 2010

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Balance in AOCI as of December 31, 2009	$ (2)	$ (13)	$ (15)
Changes in Fair Value Recognized in AOCI	9	13	22
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:			
Utility Operations Revenues	-	-	-
Other Revenues	(7)	-	(7)
Purchased Electricity for Resale	4	-	4
Interest Expense	-	4	4
Regulatory Assets (a)	3	-	3
Regulatory Liabilities (a)	-	-	-
Balance in AOCI as of December 31, 2010	$ 7	$ 4	$ 11

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
Year Ended December 31, 2009

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Balance in AOCI as of December 31, 2008	$ 7	$ (29)	$ (22)
Changes in Fair Value Recognized in AOCI	(6)	11	5
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:			
Utility Operations Revenues	(15)	-	(15)
Other Revenues	(15)	-	(15)
Purchased Electricity for Resale	29	-	29
Interest Expense	-	5	5
Regulatory Assets (a)	5	-	5
Regulatory Liabilities (a)	(7)	-	(7)
Balance in AOCI as of December 31, 2009	$ (2)	$ (13)	$ (15)

(a) Represents realized and unrealized gains and losses subject to regulatory accounting treatment recorded as either current or noncurrent on the balance sheets.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on our balance sheets at December 31, 2011 and 2010 were:

Impact of Cash Flow Hedges on the Balance Sheet
December 31, 2011

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Hedging Assets (a)	$ 20	$ -	$ 20
Hedging Liabilities (a)	25	42	67
AOCI Gain (Loss) Net of Tax	(3)	(20)	(23)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	(3)	(2)	(5)

Impact of Cash Flow Hedges on the Balance Sheet
December 31, 2010

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Hedging Assets (a)	$ 13	$ 25	$ 38
Hedging Liabilities (a)	2	4	6
AOCI Gain (Loss) Net of Tax	7	4	11
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	3	(2)	1

(a) Hedging Assets and Hedging Liabilities are included in Risk Management Assets and Liabilities on our balance sheets.

The actual amounts that we reclassify from Accumulated Other Comprehensive Income (Loss) to Net Income can differ from the estimate above due to market price changes. As of December 31, 2011, the maximum length of time that we are hedging (with contracts subject to the accounting guidance for "Derivatives and Hedging") our exposure to variability in future cash flows related to forecasted transactions is 30 months.

Credit Risk

We limit credit risk in our wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. We use Moody's, Standard and Poor's and current market-based qualitative and quantitative data as well as financial statements to assess the financial health of counterparties on an ongoing basis.

We use standardized master agreements which may include collateral requirements. These master agreements facilitate the netting of cash flows associated with a single counterparty. Cash, letters of credit and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. The collateral agreements require a counterparty to post cash or letters of credit in the event an exposure exceeds our established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with our credit policy. In addition, collateral agreements allow for termination and liquidation of all positions in the event of a failure or inability to post collateral.

Collateral Triggering Events

Under the tariffs of the RTOs and Independent System Operators (ISOs) and a limited number of derivative and non-derivative contracts primarily related to our competitive retail auction loads, we are obligated to post an additional amount of collateral if our credit ratings decline below investment grade. The amount of collateral required fluctuates based on market prices and our total exposure. On an ongoing basis, our risk management organization assesses the appropriateness of these collateral triggering items in contracts. AEP and its subsidiaries have not experienced a downgrade below investment grade. The following table represents: (a) our aggregate fair value of such derivative contracts, (b) the amount of collateral we would have been required to post for all derivative and non-derivative contracts if our credit ratings had declined below investment grade and (c) how much was attributable to RTO and ISO activities as of December 31, 2011 and 2010:

	December 31, 2011	December 31, 2010
	(in millions)	
Liabilities for Derivative Contracts with Credit Downgrade Triggers	$ 32	$ 20
Amount of Collateral AEP Subsidiaries Would Have Been Required to Post	39	45
Amount Attributable to RTO and ISO Activities	38	44

In addition, a majority of our non-exchange traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event by Parent or the obligor under outstanding debt or a third party obligation in excess of $50 million. On an ongoing basis, our risk management organization assesses the appropriateness of these cross-default provisions in our contracts. We do not anticipate a non-performance event under these provisions. The following table represents: (a) the fair value of these derivative liabilities subject to cross-default provisions prior to consideration of contractual netting arrangements, (b) the amount this exposure has been reduced by cash collateral we have posted and (c) if a cross-default provision would have been triggered, the settlement amount that would be required after considering our contractual netting arrangements as of December 31, 2011 and 2010:

	December 31, 2011	December 31, 2010
	(in millions)	
Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	$ 515	$ 401
Amount of Cash Collateral Posted	56	81
Additional Settlement Liability if Cross Default Provision is Triggered	291	213

10. FAIR VALUE MEASUREMENTS

Fair Value Measurements of Long-term Debt

The fair values of Long-term Debt are based on quoted market prices, without credit enhancements, for the same or similar issues and the current interest rates offered for instruments with similar maturities. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that we could realize in a current market exchange.

The book values and fair values of Long-term Debt as of December 31, 2011 and 2010 are summarized in the following table:

	December 31, 2011 Book Value	December 31, 2011 Fair Value	December 31, 2010 Book Value	December 31, 2010 Fair Value
	(in millions)			
Long-term Debt	$ 16,516	$ 19,259	$ 16,811	$ 18,285

Fair Value Measurements of Other Temporary Investments

Other Temporary Investments include funds held by trustees primarily for the payment of securitization bonds, marketable securities that we intend to hold for less than one year and investments by our protected cell of EIS. See "Other Temporary Investments" section of Note 1.

The following is a summary of Other Temporary Investments:

	December 31, 2011			
Other Temporary Investments	**Cost**	**Gross Unrealized Gains**	**Gross Unrealized Losses**	**Estimated Fair Value**
	(in millions)			
Restricted Cash (a)	$ 216	$ -	$ -	$ 216
Fixed Income Securities:				
Mutual Funds	64	-	-	64
Equity Securities - Mutual Funds	11	3	-	14
Total Other Temporary Investments	$ 291	$ 3	$ -	$ 294

	December 31, 2010			
Other Temporary Investments	**Cost**	**Gross Unrealized Gains**	**Gross Unrealized Losses**	**Estimated Fair Value**
	(in millions)			
Restricted Cash (a)	$ 225	$ -	$ -	$ 225
Fixed Income Securities:				
Mutual Funds	69	-	-	69
Variable Rate Demand Notes	97	-	-	97
Equity Securities - Mutual Funds	18	7	-	25
Total Other Temporary Investments	$ 409	$ 7	$ -	$ 416

(a) Primarily represents amounts held for the payment of debt.

The following table provides the activity for our debt and equity securities within Other Temporary Investments for the years ended December 31, 2011, 2010 and 2009:

	Years Ended December 31, 2011	2010	2009
		(in millions)	
Proceeds from Investment Sales	$ 268	$ 455	$ 35
Purchases of Investments	154	503	82
Gross Realized Gains on Investment Sales	4	16	-
Gross Realized Losses on Investment Sales	-	-	-

At December 31, 2011 and 2010, we had no Other Temporary Investments with an unrealized loss position. In 2009, we recorded $9 million ($6 million, net of tax) of other-than-temporary impairments of Other Temporary Investments for equity investments of our protected cell captive insurance company. At December 31, 2011, fixed income securities are primarily debt based mutual funds with short and intermediate maturities. Mutual funds may be sold and do not contain maturity dates.

The following table provides details of Other Temporary Investments included in Accumulated Other Comprehensive Income (Loss) on our balance sheet and the reasons for changes for the year ended December 31, 2011. All amounts in the following table are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity for Other Temporary Investments
Year Ended December 31, 2011

	(in millions)
Balance in AOCI as of December 31, 2010	$ 4
Changes in Fair Value Recognized in AOCI	1
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income:	
Interest Income	(3)
Balance in AOCI as of December 31, 2011	$ 2

Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal

I&M records securities held in trust funds for decommissioning nuclear facilities and for the disposal of SNF at fair value. See "Nuclear Trust Funds" section of Note 1.

The following is a summary of nuclear trust fund investments at December 31, 2011 and December 31, 2010:

	December 31, 2011 Estimated Fair Value	2011 Gross Unrealized Gains	2011 Other-Than-Temporary Impairments	2010 Estimated Fair Value	2010 Gross Unrealized Gains	2010 Other-Than-Temporary Impairments
			(in millions)			
Cash and Cash Equivalents	$ 18	$ -	$ -	$ 20	$ -	$ -
Fixed Income Securities:						
United States Government	544	61	(1)	461	23	(1)
Corporate Debt	54	5	(2)	59	4	(2)
State and Local Government	330	-	(2)	341	(1)	-
Subtotal Fixed Income Securities	928	66	(5)	861	26	(3)
Equity Securities - Domestic	646	215	(80)	634	183	(123)
Spent Nuclear Fuel and Decommissioning Trusts	$ 1,592	$ 281	$ (85)	$ 1,515	$ 209	$ (126)

The following table provides the securities activity within the decommissioning and SNF trusts for the years ended December 31, 2011, 2010 and 2009:

	Years Ended December 31, 2011	2010	2009
		(in millions)	
Proceeds from Investment Sales	$ 1,111	$ 1,362	$ 713
Purchases of Investments	1,167	1,415	771
Gross Realized Gains on Investment Sales	33	12	28
Gross Realized Losses on Investment Sales	22	2	1

The adjusted cost of debt securities was $862 million and $835 million as of December 31, 2011 and 2010, respectively. The adjusted cost of equity securities was $431 million and $451 million as of December 31, 2011 and 2010, respectively.

The fair value of debt securities held in the nuclear trust funds, summarized by contractual maturities, at December 31, 2011 was as follows:

	Fair Value of Debt Securities
	(in millions)
Within 1 year	$ 62
1 year – 5 years	285
5 years – 10 years	350
After 10 years	231
Total	**$ 928**

Fair Value Measurements of Financial Assets and Liabilities

For a discussion of fair value accounting and the classification of assets and liabilities within the fair value hierarchy, see the "Fair Value Measurements of Assets and Liabilities" section of Note 1.

The following tables set forth, by level within the fair value hierarchy, our financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2011 and 2010. As required by the accounting guidance for "Fair Value Measurements and Disclosures," financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There have not been any significant changes in AEP's valuation techniques.

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2011

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Cash and Cash Equivalents (a)	$ 6	$ -	$ -	$ 215	$ 221
Other Temporary Investments					
Restricted Cash (a)	191	-	-	25	216
Fixed Income Securities:					
Mutual Funds	64	-	-	-	64
Equity Securities - Mutual Funds (b)	14	-	-	-	14
Total Other Temporary Investments	269	-	-	25	294
Risk Management Assets					
Risk Management Commodity Contracts (c) (f)	47	1,299	147	(945)	548
Cash Flow Hedges:					
Commodity Hedges (c)	15	23	-	(18)	20
De-designated Risk Management Contracts (d)	-	-	-	28	28
Total Risk Management Assets	62	1,322	147	(935)	596
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	-	5	-	13	18
Fixed Income Securities:					
United States Government	-	544	-	-	544
Corporate Debt	-	54	-	-	54
State and Local Government	-	330	-	-	330
Subtotal Fixed Income Securities	-	928	-	-	928
Equity Securities - Domestic (b)	646	-	-	-	646
Total Spent Nuclear Fuel and Decommissioning Trusts	646	933	-	13	1,592
Total Assets	$ 983	$ 2,255	$ 147	$ (682)	$ 2,703
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (f)	$ 43	$ 1,209	$ 78	$ (1,052)	$ 278
Cash Flow Hedges:					
Commodity Hedges (c)	-	43	-	(18)	25
Interest Rate/Foreign Currency Hedges	-	42	-	-	42
Total Risk Management Liabilities	$ 43	$ 1,294	$ 78	$ (1,070)	$ 345

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2010

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Cash and Cash Equivalents (a)	$ 170	$ -	$ -	$ 124	$ 294
Other Temporary Investments					
Restricted Cash (a)	184	-	-	41	225
Fixed Income Securities:					
Mutual Funds	69	-	-	-	69
Variable Rate Demand Notes	-	97	-	-	97
Equity Securities - Mutual Funds (b)	25	-	-	-	25
Total Other Temporary Investments	278	97	-	41	416
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	20	1,432	112	(1,013)	551
Cash Flow Hedges:					
Commodity Hedges (c)	11	17	-	(15)	13
Interest Rate/Foreign Currency Hedges	-	25	-	-	25
Fair Value Hedges	-	7	-	-	7
De-designated Risk Management Contracts (d)	-	-	-	46	46
Total Risk Management Assets	31	1,481	112	(982)	642
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	-	8	-	12	20
Fixed Income Securities:					
United States Government	-	461	-	-	461
Corporate Debt	-	59	-	-	59
State and Local Government	-	341	-	-	341
Subtotal Fixed Income Securities	-	861	-	-	861
Equity Securities - Domestic (b)	634	-	-	-	634
Total Spent Nuclear Fuel and Decommissioning Trusts	634	869	-	12	1,515
Total Assets	$ 1,113	$ 2,447	$ 112	$ (805)	$ 2,867
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ 25	$ 1,325	$ 27	$ (1,114)	$ 263
Cash Flow Hedges:					
Commodity Hedges (c)	4	13	-	(15)	2
Interest Rate/Foreign Currency Hedges	-	4	-	-	4
Fair Value Hedges	-	1	-	-	1
Total Risk Management Liabilities	$ 29	$ 1,343	$ 27	$ (1,129)	$ 270

(a) Amounts in "Other" column primarily represent cash deposits in bank accounts with financial institutions or with third parties. Level 1 amounts primarily represent investments in money market funds.
(b) Amounts represent publicly traded equity securities and equity-based mutual funds.
(c) Amounts in "Other" column primarily represent counterparty netting of risk management and hedging contracts and associated cash collateral under the accounting guidance for "Derivatives and Hedging."
(d) Represents contracts that were originally MTM but were subsequently elected as normal under the accounting guidance for "Derivatives and Hedging." At the time of the normal election, the MTM value was frozen and no longer fair valued. This MTM value will be amortized into revenues over the remaining life of the contracts.
(e) Amounts in "Other" column primarily represent accrued interest receivables from financial institutions. Level 2 amounts primarily represent investments in money market funds.
(f) The December 31, 2011 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 1 matures $3 million in 2012, $7 million in periods 2013-2015 and ($6) million in periods 2016-2018; Level 2 matures $21 million in 2012, $50 million in periods 2013-2015, $11 million in periods 2016-2017 and $8 million in periods 2018-2030; Level 3 matures ($19) million in 2012, $44 million in periods 2013-2015, $18 million in periods 2016-2017 and $26 million in periods 2018-2030. Risk management commodity contracts are substantially comprised of power contracts.
(g) The December 31, 2010 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 1 matures ($2) million in 2011, $2 million in periods 2012-2014 and ($5) million in periods 2015-2018; Level 2 matures $13 million in 2011, $66 million in periods 2012-2014, $12 million in periods 2015-2016 and $16 million in periods 2017-2028; Level 3 matures $18 million in 2011, $24 million in periods 2012-2014, $16 million in periods 2015-2016 and $27 million in periods 2017-2028. Risk management commodity contracts are substantially comprised of power contracts.

There have been no transfers between Level 1 and Level 2 during the years ended December 31, 2011 and 2010.

The following tables set forth a reconciliation of changes in the fair value of net trading derivatives and other investments classified as Level 3 in the fair value hierarchy:

Year Ended December 31, 2011	Net Risk Management Assets (Liabilities) (in millions)
Balance as of December 31, 2010	$ 85
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(10)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	9
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-
Purchases, Issuances and Settlements (c)	(3)
Transfers into Level 3 (d) (f)	13
Transfers out of Level 3 (e) (f)	(12)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	(13)
Balance as of December 31, 2011	$ 69

Year Ended December 31, 2010	Net Risk Management Assets (Liabilities) (in millions)
Balance as of December 31, 2009	$ 62
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	5
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	63
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-
Purchases, Issuances and Settlements (c)	(25)
Transfers into Level 3 (d) (f)	18
Transfers out of Level 3 (e) (f)	(53)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	15
Balance as of December 31, 2010	$ 85

Year Ended December 31, 2009	Net Risk Management Assets (Liabilities) (in millions)
Balance as of December 31, 2008	$ 49
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(4)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	44
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-
Purchases, Issuances and Settlements (c)	(17)
Transfers in and/or out of Level 3 (h)	(25)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	15
Balance as of December 31, 2009	$ 62

(a) Included in revenues on our statements of income.
(b) Represents the change in fair value between the beginning of the reporting period and the settlement of the risk management commodity contract.
(c) Represents the settlement of risk management commodity contracts for the reporting period.
(d) Represents existing assets or liabilities that were previously categorized as Level 2.
(e) Represents existing assets or liabilities that were previously categorized as Level 3.
(f) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.
(g) Relates to the net gains (losses) of those contracts that are not reflected on our statements of income. These net gains (losses) are recorded as regulatory liabilities/assets.
(h) Represents existing assets or liabilities that were either previously categorized as a higher level for which the inputs to the model became unobservable or assets and liabilities that were previously classified as Level 3 for which the lowest significant input became observable during the period.

11. INCOME TAXES

The details of our consolidated income taxes before extraordinary items as reported are as follows:

	Years Ended December 31, 2011	2010	2009
		(in millions)	
Federal:			
Current	$ 20	$ (134)	$ (575)
Deferred	786	760	1,171
Total Federal	806	626	596
State and Local:			
Current	37	(20)	(76)
Deferred	(25)	38	55
Total State and Local	12	18	(21)
International:			
Current	-	(1)	-
Deferred	-	-	-
Total International	-	(1)	-
Income Tax Expense	$ 818	$ 643	$ 575

The following is a reconciliation of our consolidated difference between the amount of federal income taxes computed by multiplying book income before income taxes by the federal statutory tax rate and the amount of income taxes reported.

	Years Ended December 31, 2011	2010	2009
		(in millions)	
Net Income	$ 1,949	$ 1,218	$ 1,365
Extraordinary Items, Net of Tax of $(112) million and $3 million in 2011 and 2009, respectively	(373)	-	5
Income Before Extraordinary Items	1,576	1,218	1,370
Income Tax Expense	818	643	575
Pretax Income	$ 2,394	$ 1,861	$ 1,945
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 838	$ 651	$ 681
Increase (Decrease) in Income Taxes resulting from the following items:			
Depreciation	41	47	31
Investment Tax Credits, Net	(15)	(16)	(19)
Energy Production Credits	(18)	(20)	(15)
State and Local Income Taxes, Net	(22)	11	(14)
Removal Costs	(20)	(19)	(19)
AFUDC	(42)	(33)	(36)
Medicare Subsidy	1	12	(11)
Valuation Allowance	86	-	-
Tax Reserve Adjustments	2	(16)	(6)
Other	(33)	26	(17)
Income Tax Expense	$ 818	$ 643	$ 575
Effective Income Tax Rate	34.2 %	34.6 %	29.6 %

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

	December 31, 2011	December 31, 2010
	(in millions)	
Deferred Tax Assets	$ 2,855	$ 2,519
Deferred Tax Liabilities	(11,185)	(10,009)
Net Deferred Tax Liabilities	$ (8,330)	$ (7,490)
Property Related Temporary Differences	$ (5,963)	$ (5,301)
Amounts Due from Customers for Future Federal Income Taxes	(259)	(250)
Deferred State Income Taxes	(668)	(622)
Securitized Transition Assets	(621)	(651)
Regulatory Assets	(1,208)	(867)
Postretirement Benefits	424	356
Accrued Pensions	149	218
Deferred Income Taxes on Other Comprehensive Loss	254	207
Accrued Nuclear Decommissioning	(436)	(395)
Net Operating Loss Carryforward	125	-
Tax Credit Carryforward	182	-
Valuation Allowance	(86)	-
All Other, Net	(223)	(185)
Net Deferred Tax Liabilities	$ (8,330)	$ (7,490)

AEP System Tax Allocation Agreement

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

Federal and State Income Tax Audit Status

We are no longer subject to U.S. federal examination for years before 2009. We completed the examination of the years 2007 and 2008 in April 2011 and settled all outstanding issues on appeal for the years 2001 through 2006 in October 2011. The settlements did not have a material impact on net income, cash flows or financial condition. The IRS examination of years 2009 and 2010 started in October 2011. Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for federal income taxes have been made for potential liabilities resulting from such matters. In addition, we accrue interest on these uncertain tax positions. We are not aware of any issues for open tax years that upon final resolution are expected to have a material effect on net income.

We, along with our subsidiaries, file income tax returns in various state, local and foreign jurisdictions. These taxing authorities routinely examine our tax returns and we are currently under examination in several state and local jurisdictions. We believe that we have filed tax returns with positions that may be challenged by these tax authorities. Management believes that adequate provisions for income taxes have been made for potential liabilities resulting from such challenges and the ultimate resolution of these audits will not materially impact net income. With few exceptions, we are no longer subject to state, local or non-U.S. income tax examinations by tax authorities for years before 2000.

Net Income Tax Operating Loss Carryforward

In 2011, we sustained a federal net income tax operating loss of $226 million driven primarily by bonus depreciation, pension plan contributions and other book versus tax temporary differences. We also had state net income tax operating loss carryforwards as indicated in the table below. As a result, we accrued deferred federal, state and local income tax benefits in 2011. We expect to realize the federal, state and local cash flow benefit in future periods as there was insufficient capacity in prior periods to carry the net operating loss back. We anticipate future taxable income will be sufficient to realize the net income tax operating loss tax benefits before the federal carryforward expires after 2031.

State	State Net Income Tax Operating Loss Carryforward	Year of Expiration
	(in millions)	
Oklahoma	$ 135	2031
Tennessee	13	2026
Virginia	358	2031
West Virginia	511	2031

We sustained federal, state and local net income tax operating losses in 2009 driven primarily by bonus depreciation, a change in tax accounting method related to units of property and other book versus tax temporary differences. As a result, we accrued current federal, state and local income tax benefits in 2009. We realized the federal cash flow benefit in 2010 as there was sufficient capacity in prior periods to carry the net operating loss back. Most of our state and local jurisdictions do not provide for a net operating loss carry back, therefore the state and local losses were carried forward to future periods.

Tax Credit Carryforward

Federal and state net income tax operating losses sustained in 2009 and 2011 along with lower federal and state taxable income in 2010 resulted in unused federal and state income tax credits. At December 31, 2011, we have total federal tax credit carryforwards of $182 million and total state tax credit carryforwards of $74 million, not all of which are subject to an expiration date. If these credits are not utilized, the federal general business tax credits of $81 million will expire in the years 2028 through 2031 and the state coal tax credits of $29 million will expire in the years 2013 through 2021.

We anticipate future federal taxable income will be sufficient to realize the tax benefits of the federal tax credits before they expire unused. We do not anticipate state taxable income will be sufficient in future periods to realize the tax benefits of all state income tax credits before they expire unused and we have provided a valuation allowance accordingly.

Valuation Allowance

We assess past results and future operations to estimate and evaluate available positive and negative evidence to evaluate whether sufficient future taxable income will be generated to use existing deferred tax assets. A significant piece of objective negative information evaluated were the net income tax operating losses sustained in 2009 and 2011. On the basis of this evaluation of available positive and negative evidence, as of December 31, 2011, a valuation allowance of $30 million for state tax credits, net of federal tax, and $56 million for an unrealized capital loss has been recorded in order to measure only the portion of the deferred tax assets that, more likely than not, will be realized. The amount of the deferred tax assets considered realizable, however, could be adjusted if estimates of future taxable income during the carryforward period are reduced or if objective negative evidence in the form of cumulative losses is no longer present and additional weight may be given to subjective evidence, such as our projections for growth.

For a discussion of the tax implications of the unrealized capital loss resulting from our settlement with BOA and Enron, see "Enron Bankruptcy" section of Note 5.

Uncertain Tax Positions

We recognize interest accruals related to uncertain tax positions in interest income or expense, as applicable, and penalties in Other Operation in accordance with the accounting guidance for "Income Taxes."

The following table shows amounts reported for interest expense, interest income and reversal of prior period interest expense:

	Years Ended December 31, 2011	2010	2009
		(in millions)	
Interest Expense	$ 8	$ 8	$ 1
Interest Income	22	11	5
Reversal of Prior Period Interest Expense	13	5	5

The following table shows balances for amounts accrued for the receipt of interest and the payment of interest and penalties:

	December 31, 2011	2010
	(in millions)	
Accrual for Receipt of Interest	$ 13	$ 42
Accrual for Payment of Interest and Penalties	6	21

The reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

	2011	2010	2009
		(in millions)	
Balance at January 1,	$ 219	$ 237	$ 237
Increase - Tax Positions Taken During a Prior Period	51	40	56
Decrease - Tax Positions Taken During a Prior Period	(43)	(43)	(65)
Increase - Tax Positions Taken During the Current Year	10	-	16
Decrease - Tax Positions Taken During the Current Year	-	(6)	-
Increase - Settlements with Taxing Authorities	-	-	1
Decrease - Settlements with Taxing Authorities	(31)	(2)	-
Decrease - Lapse of the Applicable Statute of Limitations	(38)	(7)	(8)
Balance at December 31,	$ 168	$ 219	$ 237

The total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate is $111 million, $112 million and $137 million for 2011, 2010 and 2009, respectively. We believe there will be no significant net increase or decrease in unrecognized tax benefits within 12 months of the reporting date.

Federal Tax Legislation

Under the Energy Tax Incentives Act of 2005, we filed applications with the United States Department of Energy and the IRS in 2008 for the West Virginia IGCC project and in July 2008 the IRS allocated the project $134 million in credits. In September 2008, we entered into a memorandum of understanding with the IRS concerning the requirements of claiming the credits. We had until July 2010 to meet certain minimum requirements under the agreement with the IRS or the credits would be forfeited. In July 2010, we forfeited the allocated tax credits.

The American Recovery and Reinvestment Tax Act of 2009 provided for several new grant programs and expanded tax credits and an extension of the 50% bonus depreciation provision enacted in the Economic Stimulus Act of 2008. The enacted provisions did not have a material impact on net income or financial condition. However, the bonus depreciation contributed to the 2009 federal net operating tax loss that resulted in a 2010 cash flow benefit of $419 million.

The Patient Protection and Affordable Care Act and the related Health Care and Education Reconciliation Act (Health Care Acts) were enacted in March 2010. The Health Care Acts amend tax rules so that the portion of employer health care costs that are reimbursed by the Medicare Part D prescription drug subsidy will no longer be deductible by the employer for federal income tax purposes effective for years beginning after December 31, 2012. Because of the loss of the future tax deduction, a reduction in the deferred tax asset related to the nondeductible OPEB liabilities accrued to date was recorded in March 2010. This reduction did not materially affect our cash flows or financial condition. For the year ended December 31, 2010, deferred tax assets decreased $56 million, partially offset by recording net tax regulatory assets of $35 million in our jurisdictions with regulated operations, resulting in a decrease in net income of $21 million.

The Small Business Jobs Act (the Act) was enacted in September 2010. Included in the Act was a one-year extension of the 50% bonus depreciation provision. The Tax Relief, Unemployment Insurance Reauthorization and the Job Creation Act of 2010 extended the life of research and development, employment and several energy tax credits originally scheduled to expire at the end of 2010. In addition, the Act extended the time for claiming bonus depreciation and increased the deduction to 100% for part of 2010 and 2011. The enacted provisions will not have a material impact on net income or financial condition but had a favorable impact on cash flows of $318 million in 2010.

In December of 2011 the U.S. Treasury Department issued guidance regarding the deduction and capitalization of expenditures related to tangible property. The guidance was in the form of proposed and temporary regulations and generally is effective for tax years beginning in 2012. These regulations did not have an impact on either net income or cash flow in 2011. We are still evaluating the impact these regulations will have on future periods.

State Tax Legislation

Ohio House Bill 66 of 2005 imposed a commercial activity tax at a fully phased-in rate of 0.26% on all Ohio gross receipts. The tax was phased-in over a five-year period that began July 1, 2005 at 23% of the full 0.26% rate. As a result of this tax, expenses of approximately $14 million, $13 million and $11 million were recorded in 2011, 2010 and 2009, respectively, in Taxes Other Than Income Taxes.

Legislation was passed by the state of Indiana in May 2011 enacting a phased reduction in corporate income tax rates from 8.5% to 6.5%. The current 8.5% Indiana corporate income tax rate is scheduled for a 0.5% reduction each year beginning after June 30, 2012 with the final reduction occurring in years beginning after June 30, 2015.

In May 2011, Michigan repealed its Business Tax regime and replaced it with a traditional corporate net income tax with a rate of 6%, effective January 1, 2012.

During the third quarter of 2011, the state of West Virginia determined that the state had achieved certain minimum levels of shortfall reserve funds and thus, the West Virginia corporate income tax rate will be reduced to 7.75% in 2012. The enacted provisions will not have a material impact on net income, cash flows or financial condition.

12. LEASES

Leases of property, plant and equipment are for periods up to 60 years and require payments of related property taxes, maintenance and operating costs. The majority of the leases have purchase or renewal options and will be renewed or replaced by other leases.

Lease rentals for both operating and capital leases are generally charged to Other Operation and Maintenance expense in accordance with rate-making treatment for regulated operations. Additionally, for regulated operations with capital leases, a capital lease asset and offsetting liability are recorded at the present value of the remaining lease payments for each reporting period. Capital leases for nonregulated property are accounted for as if the assets were owned and financed. The components of rental costs are as follows:

Lease Rental Costs	Years Ended December 31, 2011	2010	2009
		(in millions)	
Net Lease Expense on Operating Leases	$ 343	$ 343	$ 354
Amortization of Capital Leases	72	97	83
Interest on Capital Leases	32	26	13
Total Lease Rental Costs	$ 447	$ 466	$ 450

The following table shows the property, plant and equipment under capital leases and related obligations recorded on our balance sheets. Capital lease obligations are included in Other Current Liabilities and Deferred Credits and Other Noncurrent Liabilities on our balance sheets.

Property, Plant and Equipment Under Capital Leases	December 31, 2011	2010
	(in millions)	
Generation	$ 104	$ 97
Other Property, Plant and Equipment	485	482
Total Property, Plant and Equipment Under Capital Leases	589	579
Accumulated Amortization	137	108
Net Property, Plant and Equipment Under Capital Leases	$ 452	$ 471
Obligations Under Capital Leases		
Noncurrent Liability	$ 384	$ 398
Liability Due Within One Year	74	76
Total Obligations Under Capital Leases	$ 458	$ 474

Future minimum lease payments consisted of the following at December 31, 2011:

Future Minimum Lease Payments	Capital Leases	Noncancelable Operating Leases
	(in millions)	
2012	$ 96	$ 316
2013	81	288
2014	67	264
2015	55	245
2016	47	226
Later Years	285	1,235
Total Future Minimum Lease Payments	631	$ 2,574
Less Estimated Interest Element	173	
Estimated Present Value of Future Minimum Lease Payments	$ 458	

Master Lease Agreements

We lease certain equipment under master lease agreements. In December 2010, we signed a new master lease agreement with GE Capital Commercial Inc. (GE) for approximately $137 million to replace existing operating and capital leases with GE. We refinanced $60 million of capital leases and $77 million of operating leases. These assets were included in existing master lease agreements that were to be terminated in 2011 since GE exercised the termination provision related to these leases in 2008. In January 2011, we purchased $5 million of previously leased assets that were not included in the 2010 refinancing. In June 2011, we placed an additional $11 million of previously leased assets under a new capital lease. These obligations are included in the future minimum lease payments schedule earlier in this note.

For equipment under the GE master lease agreements, the lessor is guaranteed receipt of up to 78% of the unamortized balance of the equipment at the end of the lease term. If the fair value of the leased equipment is below the unamortized balance at the end of the lease term, we are committed to pay the difference between the fair value and the unamortized balance, with the total guarantee not to exceed 78% of the unamortized balance. For equipment under other master lease agreements, the lessor is guaranteed a residual value up to a stated percentage of either the unamortized balance or the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, we are committed to pay the difference between the actual fair value and the residual value guarantee. At December 31, 2011, the maximum potential loss for these lease agreements was approximately $14 million assuming the fair value of the equipment is zero at the end of the lease term. Historically, at the end of the lease term the fair value has been in excess of the unamortized balance.

Rockport Lease

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

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the Plant and leases it equally to AEGCo and I&M. The lease is accounted for as an operating lease with the payment obligations included in the future minimum lease payments schedule earlier in this note. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the Plant. AEP, AEGCo and I&M have no ownership interest in the Owner Trustee and do not guarantee its debt. The future minimum lease payments for this sale-and-leaseback transaction as of December 31, 2011 are as follows:

Future Minimum Lease Payments	AEGCo	I&M
	(in millions)	
2012	$ 74	$ 74
2013	74	74
2014	74	74
2015	74	74
2016	74	74
Later Years	443	443
Total Future Minimum Lease Payments	$ 813	$ 813

Railcar Lease

In June 2003, AEP Transportation LLC (AEP Transportation), a subsidiary of AEP, entered into an agreement with BTM Capital Corporation, as lessor, to lease 875 coal-transporting aluminum railcars. The lease is accounted for as an operating lease. In January 2008, AEP Transportation assigned the remaining 848 railcars under the original lease agreement to I&M (390 railcars) and SWEPCo (458 railcars). The assignment is accounted for as operating leases for I&M and SWEPCo. The initial lease term was five years with three consecutive five-year renewal periods for a maximum lease term of twenty years. I&M and SWEPCo intend to renew these leases for the full lease term of twenty years via the renewal options. The future minimum lease obligations are $16 million for I&M and $18 million for SWEPCo for the remaining railcars as of December 31, 2011. These obligations are included in the future minimum lease payments schedule earlier in this note.

Under the lease agreement, the lessor is guaranteed that the sale proceeds under a return-and-sale option will equal at least a lessee obligation amount specified in the lease, which declines from approximately 84% under the current five year lease term to 77% at the end of the 20-year term of the projected fair value of the equipment. I&M and SWEPCo have assumed the guarantee under the return-and-sale option. I&M's maximum potential loss related to the guarantee is approximately $12 million and SWEPCo's is approximately $13 million assuming the fair value of the equipment is zero at the end of the current five-year lease term. However, we believe that the fair value would produce a sufficient sales price to avoid any loss.

Sabine Dragline Lease

During 2009, Sabine, an entity consolidated in accordance with the accounting guidance for "Variable Interest Entities," entered into capital lease arrangements with a nonaffiliated company to finance the purchase of two electric draglines to be used for Sabine's mining operations totaling $47 million. The amounts included in the lease represented the aggregate fair value of the existing equipment and a sale-and-leaseback transaction for additional dragline rebuild costs required to keep the dragline operational. In addition to the 2009 transactions, Sabine has one additional $53 million dragline completed in 2008 that was financed under a capital lease. These capital lease assets are included in Other Property, Plant and Equipment on our December 31, 2011 and 2010 balance sheets. The short-term and long-term capital lease obligations are included in Other Current Liabilities and Deferred Credits and Other Noncurrent Liabilities on our December 31, 2011 and 2010 balance sheets. The future payment obligations are included in our future minimum lease payments schedule earlier in this note.

I&M Nuclear Fuel Lease

In December 2007, I&M entered into a sale-and-leaseback transaction with Citicorp Leasing, Inc. (CLI), an unrelated, unconsolidated, wholly-owned subsidiary of Citibank, N.A. to lease nuclear fuel for I&M's Cook Plant. In December 2007, I&M sold a portion of its unamortized nuclear fuel inventory to CLI at cost for $85 million. The lease has a variable rate based on one month LIBOR and is accounted for as a capital lease with lease terms up to 60 months. The future payment obligations of $383 thousand are included in our future minimum lease payments schedule earlier in this note. The net capital lease asset is included in Other Property, Plant and Equipment and the short-term and long-term capital lease obligations are included in Other Current Liabilities and Deferred Credits and Other Noncurrent Liabilities, respectively, on our December 31, 2011 and 2010 balance sheets. The future minimum lease payments for this sale-and-leaseback transaction as of December 31, 2011 are $383 thousand for 2012, based on estimated fuel burn.

13. FINANCING ACTIVITIES

AEP Common Stock

In April 2009, we issued 69 million shares of common stock at $24.50 per share for net proceeds of $1.64 billion, which were primarily used to repay cash drawn under our credit facilities in the second quarter of 2009.

Set forth below is a reconciliation of common stock share activity for the years ended December 31, 2011, 2010 and 2009:

Shares of AEP Common Stock	Issued	Held In Treasury
Balance, December 31, 2008	426,321,248	20,249,992
Issued	72,012,017	-
Treasury Stock Acquired	-	28,866
Balance, December 31, 2009	498,333,265	20,278,858
Issued	2,781,616	-
Treasury Stock Acquired	-	28,867
Balance, December 31, 2010	501,114,881	20,307,725
Issued	2,644,579	-
Treasury Stock Acquired	-	28,867
Balance, December 31, 2011	503,759,460	20,336,592

Preferred Stock

In December 2011, AEP subsidiaries redeemed all of their outstanding preferred stock with a par value of $60 million at a premium, resulting in a $2.8 million loss, which is included in Preferred Stock Dividend Requirements of Subsidiaries Including Capital Stock Expense on our statement of income. The redeemed shares are no longer outstanding and represent only the right to receive the applicable redemption price, to the extent the shares have not yet been presented for payment.

Long-term Debt

Type of Debt and Maturity	Weighted Average Interest Rate at December 31, 2011	Interest Rate Ranges at December 31, 2011	Interest Rate Ranges at December 31, 2010	Outstanding at December 31, 2011	Outstanding at December 31, 2010
				(in millions)	
Senior Unsecured Notes					
2011-2040	5.85%	0.955%-8.13%	0.702%-8.13%	$ 11,737	$ 11,669
Pollution Control Bonds (a)					
2011-2038 (b)	3.57%	0.06%-6.30%	0.29%-6.30%	2,112	2,263
Notes Payable (c)					
2011-2026	4.77%	2.029%-8.03%	2.07%-8.03%	402	396
Securitization Bonds					
2013-2020	5.36%	4.98%-6.25%	4.98%-6.25%	1,688	1,847
Junior Subordinated Debentures (d)					
2063	8.75%	8.75%	8.75%	315	315
Spent Nuclear Fuel Obligation (e)				265	265
Other Long-term Debt					
2011-2059	6.07%	3.00%-13.718%	1.3125%-13.718%	29	91
Fair Value of Interest Rate Hedges				7	6
Unamortized Discount, Net				(39)	(41)
Total Long-term Debt Outstanding				16,516	16,811
Long-term Debt Due Within One Year				1,433	1,309
Long-term Debt				$ 15,083	$ 15,502

(a) For certain series of pollution control bonds, interest rates are subject to periodic adjustment. Certain series may be purchased on demand at periodic interest adjustment dates. Letters of credit from banks, standby bond purchase agreements and insurance policies support certain series.

(b) Certain pollution control bonds are subject to redemption earlier than the maturity date. Consequently, these bonds have been classified for maturity purposes as Long-term Debt Due Within One Year on our balance sheets.

(c) Notes payable represent outstanding promissory notes issued under term loan agreements and credit agreements with a number of banks and other financial institutions. At expiration, all notes then issued and outstanding are due and payable. Interest rates are both fixed and variable. Variable rates generally relate to specified short-term interest rates.

(d) Debentures will mature on March 1, 2063, subject to extensions to no later than March 1, 2068, and are callable at par any time on or after March 1, 2013.

(e) Spent nuclear fuel obligation consists of a liability along with accrued interest for disposal of spent nuclear fuel (see "SNF Disposal" section of Note 5).

Long-term debt outstanding at December 31, 2011 is payable as follows:

	2012	2013	2014	2015	2016	After 2016	Total
				(in millions)			
Principal Amount	$ 1,433	$ 1,383	$ 1,074	$ 1,496	$ 712	$ 10,457	$ 16,555
Unamortized Discount, Net							(39)
Total Long-term Debt Outstanding							$ 16,516

In January 2012, TCC retired $98 million of its outstanding Securitization Bonds.

In January and February 2012, I&M retired $2 million and $12 million, respectively, of Notes Payable related to DCC Fuel.

In February 2012, SWEPCo issued $275 million of 3.55% Senior Unsecured Notes due in 2022 and $65 million of 4.58% Notes Payable due in 2032.

In February 2012, APCo retired $30 million of 6.05% Pollution Control Bonds due in 2024 and $19.5 million of 5% Pollution Control Bonds due in 2021. As of December 31, 2011, these bonds were classified for maturity purposes as Long-term Debt Due Within One Year on our balance sheet.

As of December 31, 2011, trustees held, on our behalf, $478 million of our reacquired Pollution Control Bonds.

Dividend Restrictions

Parent Restrictions

The holders of our common stock are entitled to receive the dividends declared by our Board of Directors provided funds are legally available for such dividends. Our income derives from our common stock equity in the earnings of our utility subsidiaries.

Pursuant to the leverage restrictions in our credit agreements, we must maintain a percentage of debt to total capitalization at a level that does not exceed 67.5%. The payment of cash dividends indirectly results in an increase in the percentage of debt to total capitalization of the company distributing the dividend. The method for calculating outstanding debt and capitalization is contractually defined in the credit agreements. None of AEP's retained earnings were restricted for the purpose of the payment of dividends.

We have issued $315 million of Junior Subordinated Debentures. The debentures will mature on March 1, 2063, subject to extensions to no later than March 1, 2068, and are callable at par any time on or after March 1, 2013. We have the option to defer interest payments on the debentures for one or more periods of up to 10 consecutive years per period. During any period in which we defer interest payments, we may not declare or pay any dividends or distributions on, or redeem, repurchase or acquire our common stock. We do not anticipate any deferral of those interest payments in the foreseeable future.

Utility Subsidiaries' Restrictions

Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of our utility subsidiaries to transfer funds to us in the form of dividends. Specifically, several of our public utility subsidiaries have credit agreements that contain a covenant that limits their debt to capitalization ratio to 67.5%. At December 31, 2011, the amount of restricted net assets of AEP's subsidiaries that may not be distributed to Parent in the form of a loan, advance or dividend was approximately $6 billion.

The Federal Power Act prohibits the utility subsidiaries from participating "in the making or paying of any dividends of such public utility from any funds properly included in capital account." The term "capital account" is not defined in the Federal Power Act or its regulations. Management understands "capital account" to mean the value of the common stock. This restriction does not limit the ability of the utility subsidiaries to pay dividends out of retained earnings.

Lines of Credit and Short-term Debt

We use our commercial paper program to meet the short-term borrowing needs of our subsidiaries. The program is used to fund both a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds the majority of the nonutility subsidiaries. In addition, the program also funds, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either money pool for regulatory or operational reasons. As of December 31, 2011, we had credit facilities totaling $3.25 billion to support our commercial paper program. The maximum amount of commercial paper outstanding during 2011 was $1.2 billion and the weighted average interest rate of commercial paper outstanding during the year was 0.4%. Our outstanding short-term debt was as follows:

	December 31,			
	2011		2010	
Type of Debt	**Outstanding Amount**	**Interest Rate (a)**	**Outstanding Amount**	**Interest Rate (a)**
	(in millions)		**(in millions)**	
Securitized Debt for Receivables (b)	$ 666	0.27 %	$ 690	0.31 %
Commercial Paper	967	0.51 %	650	0.52 %
Line of Credit – Sabine (c)	17	1.79 %	6	2.15 %
Total Short-term Debt	$ 1,650		$ 1,346	

(a) Weighted average rate.
(b) Amount of securitized debt for receivables as accounted for under the "Transfers and Servicing" accounting guidance.
(c) This line of credit does not reduce available liquidity under AEP's credit facilities.

Credit Facilities

For a discussion of credit facilities, see "Letters of Credit" section of Note 5.

Securitized Accounts Receivable – AEP Credit

AEP Credit has a receivables securitization agreement with bank conduits. Under the securitization agreement, AEP Credit receives financing from the bank conduits for the interest in the receivables AEP Credit acquires from affiliated utility subsidiaries. AEP Credit continues to service the receivables. These securitized transactions allow AEP Credit to repay its outstanding debt obligations, continue to purchase our operating companies' receivables and accelerate AEP Credit's cash collections.

In July 2011, AEP Credit renewed its receivables securitization agreement. The agreement provides commitments of $750 million from bank conduits to finance receivables from AEP Credit with an increase to $800 million for the months of July, August and September to accommodate seasonal demand. A commitment of $375 million, with the seasonal increase to $425 million for the months of July, August and September, expires in June 2012 and the remaining commitment of $375 million expires in June 2014.

Accounts receivable information for AEP Credit is as follows:

	Years Ended December 31, 2011	2010	2009
	(dollars in millions)		
Proceeds from Sale of Accounts Receivable	$ NA	$ NA	$ 7,043
Loss on Sale of Accounts Receivable	NA	NA	3
Average Variable Discount Rate on Sale of Accounts Receivable	NA	NA	0.57 %
Effective Interest Rates on Securitization of Accounts Receivable	0.27 %	0.31 %	NA
Net Uncollectible Accounts Receivable Written Off	37	22	28

NA Not Applicable

	December 31, 2011	2010
	(in millions)	
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	$ 902	$ 923
Total Principal Outstanding	666	690
Delinquent Securitized Accounts Receivable	38	50
Bad Debt Reserves Related to Securitization/Sale of Accounts Receivable	18	26
Unbilled Receivables Related to Securitization/Sale of Accounts Receivable	370	354

Customer accounts receivable retained and securitized for our operating companies are managed by AEP Credit. AEP Credit's delinquent customer accounts receivable represents accounts greater than 30 days past due.

14. STOCK-BASED COMPENSATION

As approved by shareholder vote, the Amended and Restated American Electric Power System Long-Term Incentive Plan (LTIP) authorizes the use of 20,000,000 shares of AEP common stock for various types of stock-based compensation awards, including stock options, to employees. A maximum of 10,000,000 shares may be used under this plan for full value share awards, which includes performance units, restricted shares and restricted stock units. The AEP Board of Directors and shareholders last approved the LTIP in 2010. The following sections provide further information regarding each type of stock-based compensation award granted by the Human Resources Committee of the Board of Directors (HR Committee).

Stock Options

We did not grant stock options in 2011, 2010 or 2009 but we do have outstanding stock options from grants in earlier periods that vested or were exercised in these years. The exercise price of all outstanding stock options equaled or exceeded the market price of AEP's common stock on the date of grant. All outstanding stock options were granted with a ten-year term and generally vested, subject to the participant's continued employment, in approximately equal 1/3 increments on January 1st of the year following the first, second and third anniversary of the grant date. We record compensation cost for stock options over the vesting period based on the fair value on the grant date. The LTIP does not specify a maximum contractual term for stock options.

The total fair value of stock options vested and the total intrinsic value of options exercised are as follows:

Stock Options	Years Ended December 31, 2011	2010	2009
	(in thousands)		
Fair Value of Stock Options Vested	$ -	$ -	$ 25
Intrinsic Value of Options Exercised (a)	1,202	2,058	106

(a) Intrinsic value is calculated as market price at exercise dates less the option exercise price.

A summary of AEP stock option transactions during the years ended December 31, 2011, 2010 and 2009 is as follows:

	2011		2010		2009	
	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price
	(in thousands)		(in thousands)		(in thousands)	
Outstanding at January 1,	551	$ 32.88	1,089	$ 32.78	1,128	$ 32.73
Granted	-	NA	-	NA	-	NA
Exercised/Converted	(104)	27.39	(448)	31.53	(21)	27.20
Forfeited/Expired	(126)	46.40	(90)	38.44	(18)	36.28
Outstanding at December 31,	321	29.35	551	32.88	1,089	32.78
Options Exercisable at December 31,	321	$ 29.35	551	$ 32.88	1,089	$ 32.78

NA Not Applicable

The following table summarizes information about AEP stock options outstanding and exercisable at December 31, 2011:

2011 Range of Exercise Prices	Number of Options Outstanding and Exercisable	Weighted Average Remaining Life	Weighted Average Exercise Price	Aggregate Intrinsic Value
	(in thousands)	(in years)		(in thousands)
$27.06-27.95	162	1.27	$ 27.47	$ 2,240
$30.76-38.65	159	2.12	31.26	1,599
Total	321	1.69	29.35	$ 3,839

We include the proceeds received from exercised stock options in common stock and paid-in capital.

Performance Units

Our performance units have a value upon vesting equal to the market value of shares of AEP common stock. The number of performance units held is multiplied by the performance score to determine the actual number of performance units realized. The performance score is determined at the end of the performance period based on performance measures, which include both performance and market conditions, established for each grant at the beginning of the performance period by the HR Committee and can range from 0% to 200%. For the three-year performance and vesting period ending on December 31, 2009, performance units were paid in cash or stock at the employee's election unless they were needed to satisfy a participant's stock ownership requirement. For the three-year performance and vesting periods ending on December 31, 2010 and 2011, performance units were paid in cash, unless they were needed to satisfy a participant's stock ownership requirement. In that case, the number of units needed to satisfy the participant's largest stock ownership requirement was mandatorily deferred as AEP Career Shares until after the end of the participant's AEP career. AEP Career Shares are a form of non-qualified deferred compensation that have a value equivalent to shares of AEP common stock. AEP Career Shares are paid in cash after the participant's termination of employment. Amounts equivalent to cash dividends on both performance units and AEP Career Shares accrue as additional units. We recorded compensation cost for performance units over the three-year vesting period. The liability for both the performance units and AEP Career Shares, recorded in Employee Benefits and Pension Obligations on our balance sheets, is adjusted for changes in value. The fair value of performance unit awards is based on the estimated performance score and the current 20-day average closing price of AEP common stock at the date of valuation.

The HR Committee awarded performance units and reinvested dividends on outstanding performance units and AEP Career Shares for the years ended December 31, 2011, 2010 and 2009 as follows:

	Years Ended December 31,		
Performance Units	**2011**	**2010**	**2009**
Awarded Units (in thousands)	7	736	1,179
Weighted Average Unit Fair Value at Grant Date	$ 38.39	$ 35.43	$ 34.32
Vesting Period (in years)	3	3	3

Performance Units and AEP Career Shares (Reinvested Dividends Portion)	Years Ended December 31,		
	2011	**2010**	**2009**
Awarded Units (in thousands)	198	211	224
Weighted Average Grant Date Fair Value	$ 37.31	$ 34.70	$ 28.82
Vesting Period (in years)	(a)	(a)	(a)

(a) The vesting period for the reinvested dividends on performance units is equal to the remaining life of the related performance units. Dividends on AEP Career Shares vest immediately upon grant.

In January 2012, the HR Committee awarded 545,685 units of performance units at a grant price of $41.38 for the three-year performance and vesting period ending on December 31, 2014.

Performance scores and final awards are determined and certified by the HR Committee in accordance with the pre-established performance measures within approximately a month after the end of the performance period. The HR Committee has discretion to reduce or eliminate the value of final awards, but may not increase them. The performance scores for all open performance periods are dependent on two equally-weighted performance measures: (a) three-year total shareholder return measured relative to the electric utility and multi utility sub-industry segments of the Standard and Poor's 500 Index and (b) three-year cumulative earnings per share measured relative to an AEP Board of Directors approved target. The value of each performance unit earned is equal to the average closing price of AEP common stock for the last 20 trading days of the performance period.

The certified performance scores and units earned for the three-year period ended December 31, 2011, 2010 and 2009 were as follows:

	Years Ended December 31,		
	2011	**2010**	**2009**
Certified Performance Score	89.8 %	55.8 %	73.5 %
Performance Units Earned	1,216,926	489,013	593,175
Performance Units Mandatorily Deferred as AEP Career Shares	52,639	33,501	26,635
Performance Units Voluntarily Deferred into the Incentive Compensation Deferral Program	42,502	6,583	27,855
Performance Units to be Paid in Cash	1,121,785	448,929	538,685

The cash payouts for the years ended December 31, 2011, 2010 and 2009 were as follows:

	Years Ended December 31,		
	2011	**2010**	**2009**
		(in thousands)	
Cash Payouts for Performance Units	$ 15,985	$ 18,683	$ 30,034
Cash Payouts for AEP Career Share Distributions	2,777	3,594	2,184

Restricted Shares and Restricted Stock Units

The independent members of the AEP Board of Directors granted 300,000 restricted shares to the then Chairman, President and CEO on January 2, 2004 upon the commencement of his AEP employment. Of these restricted shares, 50,000 vested on January 1, 2005, 50,000 vested on January 1, 2006, 66,666 vested on November 30, 2009, 66,667 vested on November 30, 2010 and 66,667 vested on November 30, 2011. Compensation cost for restricted shares is measured at fair value on the grant date and recorded over the vesting period. Fair value is determined by multiplying the number of shares granted by the grant date market closing price, which was $30.76. The maximum term for these restricted shares was eight years and dividends on these restricted shares were paid in cash. AEP has not granted other restricted shares.

The HR Committee also grants restricted stock units (RSUs), which generally vest, subject to the participant's continued employment, over at least three years in approximately equal annual increments. Additional RSUs granted as dividends vest on the same date as the underlying RSUs on which the dividends were awarded. Compensation cost is measured at fair value on the grant date and recorded over the vesting period. Fair value is determined by multiplying the number of units granted by the grant date market closing price. The maximum contractual term of outstanding RSUs is six years from the grant date.

In 2010, the HR Committee granted a total of 165,520 of RSUs to four CEO succession candidates to better ensure the retention of these candidates. These grants vest, subject to the candidates' continuous employment, in three approximately equal installments on August 3, 2013, August 3, 2014 and August 3, 2015.

The HR Committee awarded RSUs, including units awarded for dividends, for the years ended December 31, 2011, 2010 and 2009 as follows:

Restricted Stock Units	Years Ended December 31, 2011	2010	2009
Awarded Units (in thousands)	121	873	130
Weighted Average Grant Date Fair Value	$ 37.07	$ 35.24	$ 29.29

In January 2012, the HR Committee awarded 363,790 units of restricted stock units at a grant price of $41.38, which vest in three approximately equal annual increments on May 1, 2013, 2014 and 2015.

The total fair value and total intrinsic value of restricted shares and restricted stock units vested during the years ended December 31, 2011, 2010 and 2009 were as follows:

Restricted Shares and Restricted Stock Units	Years Ended December 31, 2011	2010	2009
	(in thousands)		
Fair Value of Restricted Shares and Restricted Stock Units Vested	$ 7,164	$ 6,044	$ 6,573
Intrinsic Value of Restricted Shares and Restricted Stock Units Vested (a)	8,017	5,993	5,445

(a) Intrinsic value is calculated as market price at exercise date.

A summary of the status of our nonvested restricted shares and RSUs as of December 31, 2011 and changes during the year ended December 31, 2011 are as follows:

Nonvested Restricted Shares and Restricted Stock Units	Shares/Units	Weighted Average Grant Date Fair Value
	(in thousands)	
Nonvested at January 1, 2011	1,026	$ 34.88
Granted	121	37.07
Vested	(213)	33.61
Forfeited	(31)	35.35
Nonvested at December 31, 2011	903	35.46

The total aggregate intrinsic value of nonvested restricted shares and RSUs as of December 31, 2011 was $37 million and the weighted average remaining contractual life was 2.32 years.

Other Stock-Based Plans

We also have a Stock Unit Accumulation Plan for Non-employee Directors providing each non-employee director with AEP stock units as a substantial portion of their quarterly compensation for their services as a director. The number of stock units provided is based on the closing price of AEP common stock on the last trading day of the quarter for which the stock units were earned. Amounts equivalent to cash dividends on the stock units accrue as additional AEP stock units. The non-employee directors vest immediately upon award of the stock units. Stock units are paid in cash upon termination of board service or up to 10 years later if the participant so elects. Cash payments for stock units are calculated based on the average closing price of AEP common stock for the last 20 trading days prior to the distribution date.

We recorded the compensation cost for stock units when the units are awarded and adjusted the liability for changes in value based on the current 20-day average closing price of AEP common stock at the date of valuation.

We had no material cash payouts for stock unit distributions for the years ended December 31, 2011, 2010 and 2009.

The Board of Directors awarded stock units, including units awarded for dividends, for the years ended December 31, 2011, 2010 and 2009 as follows:

Stock Unit Accumulation Plan for Non-Employee Directors	Years Ended December 31, 2011	2010	2009
Awarded Units (in thousands)	52	54	56
Weighted Average Grant Date Fair Value	$ 37.72	$ 34.67	$ 29.56

Share-based Compensation Plans

Compensation cost and the actual tax benefit realized for the tax deductions from compensation cost for share-based payment arrangements recognized in income and total compensation cost capitalized in relation to the cost of an asset for the years ended December 31, 2011, 2010 and 2009 were as follows:

Share-based Compensation Plans	Years Ended December 31, 2011	2010	2009
	(in thousands)		
Compensation Cost for Share-based Payment Arrangements (a)	$ 61,807	$ 28,116	$ 31,165
Actual Tax Benefit Realized	21,632	9,841	10,908
Total Compensation Cost Capitalized	11,608	4,689	5,956

(a) Compensation cost for share-based payment arrangements is included in Other Operation and Maintenance expenses on our statements of income.

During the years ended December 31, 2011, 2010 and 2009, there were no significant modifications affecting any of our share-based payment arrangements.

As of December 31, 2011, there was $47 million of total unrecognized compensation cost related to unvested share-based compensation arrangements granted under the LTIP. Unrecognized compensation cost related to the performance units and AEP Career Shares will change as the fair value is adjusted each period and forfeitures for all award types are realized. Our unrecognized compensation cost will be recognized over a weighted-average period of 1.49 years.

Cash received from stock options exercised and actual tax benefit realized for the tax deductions from stock options exercised during the years ended December 31, 2011, 2010 and 2009 were as follows:

Share-based Compensation Plans	Years Ended December 31, 2011	2010	2009
	(in thousands)		
Cash Received from Stock Options Exercised	$ 2,855	$ 14,134	$ 567
Actual Tax Benefit Realized for the Tax Deductions from Stock Options Exercised	411	706	35

Our practice is to use authorized but unissued shares to fulfill share commitments for stock option exercises and RSU vesting. Although we do not currently anticipate any changes to this practice, we are permitted to use treasury shares, shares acquired in the open market specifically for distribution under the LTIP or any combination thereof for this purpose. The number of new shares issued to fulfill vesting RSUs is generally reduced to offset our tax withholding obligation.

15. PROPERTY, PLANT AND EQUIPMENT

Depreciation, Depletion and Amortization

We provide for depreciation of Property, Plant and Equipment, excluding coal-mining properties, on a straight-line basis over the estimated useful lives of property, generally using composite rates by functional class as follows:

2011	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges
	(in millions)			(in years)	(in millions)			(in years)
Generation	$ 14,804	$ 6,692	1.6 - 3.8 %	9 - 132	$ 10,134	$ 3,904	2.6 - 3.5 %	20 - 66
Transmission	9,048	2,600	1.3 - 2.7 %	25 - 87	-	-	- - - %	- - -
Distribution	14,783	3,828	2.4 - 4.0 %	11 - 75	-	-	- - - %	- - -
CWIP	2,913 (a)	36	NM	NM	208	1	NM	NM
Other	2,587	1,246	1.7 - 9.3 %	5 - 55	1,193	392	NM	NM
Total	$ 44,135	$ 14,402			$ 11,535	$ 4,297		

2010	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges
	(in millions)			(in years)	(in millions)			(in years)
Generation	$ 14,147	$ 6,537	1.6 - 3.8 %	9 - 132	$ 10,205	$ 3,788	2.2 - 5.1 %	20 - 70
Transmission	8,576	2,481	1.4 - 3.0 %	25 - 87	-	-	- - - %	- - -
Distribution	14,208	3,607	2.4 - 3.9 %	11 - 75	-	-	- - - %	- - -
CWIP	2,615 (a)	47	NM	NM	143	9	NM	NM
Other	2,685	1,268	3.0 - 12.5 %	5 - 55	1,161	329	NM	NM
Total	$ 42,231	$ 13,940			$ 11,509	$ 4,126		

2009	Regulated		Nonregulated	
Functional Class of Property	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges
		(in years)		(in years)
Generation	1.6 - 3.8 %	9 - 132	1.9 - 3.3 %	20 - 70
Transmission	1.4 - 2.7 %	25 - 87	- - - %	- - -
Distribution	2.4 - 3.9 %	11 - 75	- - - %	- - -
CWIP	NM	NM	NM	NM
Other	4.2 - 12.8 %	5 - 55	NM	NM

(a) Includes CWIP related to SWEPCo's Arkansas jurisdictional share of the Turk Plant.
NM Not Meaningful

We provide for depreciation, depletion and amortization of coal-mining assets over each asset's estimated useful life or the estimated life of each mine, whichever is shorter, using the straight-line method for mining structures and equipment. We use either the straight-line method or the units-of-production method to amortize mine development costs and deplete coal rights based on estimated recoverable tonnages. We include these costs in the cost of coal charged to fuel expense.

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

Asset Retirement Obligations (ARO)

We record ARO in accordance with the accounting guidance for "Asset Retirement and Environmental Obligations" for our legal obligations for asbestos removal and for the retirement of certain ash disposal facilities, closure and monitoring of underground carbon storage facilities at Mountaineer Plant, wind farms and certain coal mining facilities, as well as for nuclear decommissioning of our Cook Plant. We have identified, but not recognized, ARO liabilities related to electric transmission and distribution assets as a result of certain easements on property on which we have assets. Generally, such easements are perpetual and require only the retirement and removal of our assets upon the cessation of the property's use. We do not estimate the retirement for such easements because we plan to use our facilities indefinitely. The retirement obligation would only be recognized if and when we abandon or cease the use of specific easements, which is not expected.

The following is a reconciliation of the 2011 and 2010 aggregate carrying amounts of ARO:

	Carrying Amount of ARO
	(in millions)
ARO at December 31, 2009	$ 1,259
DHLC Deconsolidation (a)	(12)
Accretion Expense	75
Liabilities Incurred	32
Liabilities Settled	(20)
Revisions in Cash Flow Estimates	64
ARO at December 31, 2010 (b)	1,398
Accretion Expense	82
Liabilities Incurred	7
Liabilities Settled	(26)
Revisions in Cash Flow Estimates	13
ARO at December 31, 2011 (c)	$ 1,474

(a) We deconsolidated DHLC effective January 1, 2010 in accordance with the accounting guidance for "Consolidations." As a result, we record only 50% of the final reclamation based on our share of the obligation instead of the previous 100%.
(b) The current portion of our ARO, totaling $4 million, is included in Other Current Liabilities on our 2010 balance sheet.
(c) The current portion of our ARO, totaling $2 million, is included in Other Current Liabilities on our 2011 balance sheet.

As of December 31, 2011 and 2010, our ARO liability was $1.5 billion and $1.4 billion, respectively, and included $979 million and $930 million, respectively, for nuclear decommissioning of the Cook Plant. As of December 31, 2011 and 2010, the fair value of assets that are legally restricted for purposes of settling the nuclear decommissioning liabilities totaled $1.3 billion and $1.2 billion, respectively, and are recorded in Spent Nuclear Fuel and Decommissioning Trusts on our balance sheets.

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

Our amounts of allowance for borrowed, including interest capitalized, and equity funds used during construction is summarized in the following table:

	Years Ended December 31,		
	2011	**2010**	**2009**
		(in millions)	
Allowance for Equity Funds Used During Construction	$ 98	$ 77	$ 82
Allowance for Borrowed Funds Used During Construction	63	53	67

Jointly-owned Electric Facilities

We have electric facilities that are jointly-owned with nonaffiliated companies. Using our own financing, we are obligated to pay a share of the costs of these jointly-owned facilities in the same proportion as our ownership interest. Our proportionate share of the operating costs associated with such facilities is included in our statements of income and the investments and accumulated depreciation are reflected in our balance sheets under Property, Plant and Equipment as follows:

			Company's Share at December 31, 2011		
	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in millions)	
W.C. Beckjord Generating Station (Unit No. 6) (a)	Coal	12.5 %	$ 19	$ -	$ 8
Conesville Generating Station (Unit No. 4) (b)	Coal	43.5 %	310	12	54
J.M. Stuart Generating Station (c)	Coal	26.0 %	529	13	172
Wm. H. Zimmer Generating Station (a)	Coal	25.4 %	771	20	377
Dolet Hills Generating Station (Unit No. 1) (f)	Lignite	40.2 %	264	-	193
Flint Creek Generating Station (Unit No. 1) (g)	Coal	50.0 %	118	6	63
Pirkey Generating Station (Unit No. 1) (g)	Lignite	85.9 %	513	1	362
Oklaunion Generating Station (Unit No. 1) (e)	Coal	70.3 %	401	2	208
Turk Generating Plant (h)	Coal	73.33 %	-	1,326	-
Transmission	NA	(d)	63	6	50

			Company's Share at December 31, 2010		
	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in millions)	
W.C. Beckjord Generating Station (Unit No. 6) (a)	Coal	12.5 %	$ 19	$ -	$ 8
Conesville Generating Station (Unit No. 4) (b)	Coal	43.5 %	301	8	49
J.M. Stuart Generating Station (c)	Coal	26.0 %	507	23	163
Wm. H. Zimmer Generating Station (a)	Coal	25.4 %	771	10	366
Dolet Hills Generating Station (Unit No. 1) (f)	Lignite	40.2 %	258	5	192
Flint Creek Generating Station (Unit No. 1) (g)	Coal	50.0 %	116	7	62
Pirkey Generating Station (Unit No. 1) (g)	Lignite	85.9 %	503	10	358
Oklaunion Generating Station (Unit No. 1) (e)	Coal	70.3 %	395	4	201
Turk Generating Plant (h)	Coal	73.33 %	-	971	-
Transmission	NA	(d)	63	3	48

(a) Operated by Duke Energy Corporation, a nonaffiliated company.
(b) Operated by OPCo.
(c) Operated by The Dayton Power & Light Company, a nonaffiliated company.
(d) Varying percentages of ownership.
(e) Operated by PSO and also jointly-owned (54.7%) by TNC.
(f) Operated by CLECO, a nonaffiliated company.
(g) Operated by SWEPCo.
(h) Turk Generating Plant is currently under construction with a projected commercial operation date in the fourth quarter of 2012. SWEPCo jointly owns the plant with Arkansas Electric Cooperative Corporation (11.67%), East Texas Electric Cooperative (8.33%) and Oklahoma Municipal Power Authority (6.67%). Through December 2011, construction costs totaling $374 million have been billed to the other owners.
NA Not Applicable

16. COST REDUCTION INITIATIVES

In April 2010, we began initiatives to decrease both labor and non-labor expenses with a goal of achieving significant reductions in operation and maintenance expenses. A total of 2,461 positions was eliminated across the AEP System as a result of process improvements, streamlined organizational designs and other efficiencies. Most of the affected employees terminated employment May 31, 2010. The severance program provided two weeks of base pay for every year of service along with other severance benefits.

We recorded a charge of $293 million to Other Operation expense during 2010 primarily related to severance benefits as the result of headcount reduction initiatives.

The following table shows the cost reduction activity for the year ended December 31, 2011:

	Total (In millions)
Balance as of December 31, 2010	$ 17
Incurred	-
Settled	(15)
Adjustments	(2)
Balance as of December 31, 2011	$ -

17. UNAUDITED QUARTERLY FINANCIAL INFORMATION

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

	2011 Quarterly Periods Ended			
	March 31	June 30	September 30	December 31
	(in millions - except per share amounts)			
Total Revenues	$ 3,730	$ 3,609	$ 4,333	$ 3,444
Operating Income	832	717	890 (a)	343 (b)
Income Before Extraordinary Items	355	353	657 (a) (c)	211 (b) (c)
Extraordinary Items, Net of Tax	-	-	273 (c)	100 (c)
Net Income	355	353	930 (a) (c)	311 (b) (c)
Amounts Attributable to AEP Common Shareholders:				
Income Before Extraordinary Items	353	352	655 (a) (c)	208 (b) (c)
Extraordinary Items, Net of Tax	-	-	273 (c)	100 (c)
Net Income	353	352	928 (a) (c)	308 (b) (c)
Basic Earnings per Share Attributable to AEP Common Shareholders:				
Earnings per Share Before Extraordinary Items	0.73	0.73	1.35	0.43
Extraordinary Items per Share	-	-	0.57	0.20
Earnings per Share (f)	0.73	0.73	1.92	0.63
Diluted Earnings per Share Attributable to AEP Common Shareholders:				
Earnings per Share Before Extraordinary Items	0.73	0.73	1.35	0.43
Extraordinary Items per Share	-	-	0.57	0.20
Earnings per Share (f)	0.73	0.73	1.92	0.63

	2010 Quarterly Periods Ended			
	March 31	June 30	September 30	December 31
	(in millions - except per share amounts)			
Total Revenues	$ 3,569	$ 3,360	$ 4,064	$ 3,434
Operating Income	758	394 (d)	1,025	486 (e)
Net Income	346	137 (d)	557	178 (e)
Amounts Attributable to AEP Common Shareholders:				
Net Income	344	136 (d)	555	176 (e)
Basic Earnings per Share Attributable to AEP Common Shareholders:				
Earnings per Share (f)	0.72	0.28	1.16	0.37
Diluted Earnings per Share Attributable to AEP Common Shareholders:				
Earnings per Share (f)	0.72	0.28	1.16	0.37

(a) Includes pretax write-offs for plant impairments (see Note 6) and a provision for refund of POLR charges in Ohio (see Note 3).

(b) Includes a refund of POLR charges in Ohio (see Note 3) and OPCo adjustments for fuel disallowances, the 2010 SEET and the obligation to contribute to Partnership with Ohio and Ohio Growth Fund. Also includes a write-off for SWEPCo's Turk Plant (see Note 6).

(c) See "TCC Texas Restructuring" section of Note 2 and "Texas Restructuring" section of Note 3 for discussion of gains recorded in the third and fourth quarters of 2011.

(d) See Note 16 for discussion of expenses related to cost reduction initiatives in 2010.

(e) Includes a $43 million refund provision for the 2009 SEET in addition to various other provisions for certain regulatory and legal matters.

(f) Quarterly Earnings per Share amounts are meant to be stand-alone calculations and are not always additive to full-year amount due to rounding.

18. GOODWILL AND OTHER INTANGIBLE ASSETS

Goodwill

The changes in our carrying amount of goodwill for the years ended December 31, 2011 and 2010 by operating segment are as follows:

	Utility Operations	AEP River Operations	AEP Consolidated
		(in millions)	
Balance at December 31, 2009	$ 37	$ 39	$ 76
Impairment Losses	-	-	-
Balance at December 31, 2010	37	39	76
Impairment Losses	-	-	-
Balance at December 31, 2011	$ 37	$ 39	$ 76

In the fourth quarters of 2011 and 2010, we performed our annual impairment tests. The fair values of the operations with goodwill were estimated using cash flow projections and other market value indicators. There were no goodwill impairment losses. We do not have any accumulated impairment on existing goodwill.

Other Intangible Assets

Acquired intangible assets subject to amortization were $1.2 million at December 31, 2010, net of accumulated amortization and are included in Deferred Charges and Other Noncurrent Assets on our balance sheets. As of December 31, 2011, all acquired intangible assets were fully amortized. The amortization life, gross carrying amount and accumulated amortization by major asset class are as follows:

		December 31,			
		2011		2010	
	Amortization Life	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
	(in years)		(in millions)		
Easements	10	$ 2.2	$ 2.2	$ 2.2	$ 2.2
Purchased Technology	10	10.9	10.9	10.9	9.7
Total		$ 13.1	$ 13.1	$ 13.1	$ 11.9

Amortization of intangible assets was $1 million, $1 million and $3 million for 2011, 2010 and 2009, respectively.

Other than goodwill, we have no intangible assets that are not subject to amortization.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

EXECUTIVE OVERVIEW

Company Overview

As a public utility, APCo engages in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 960,000 retail customers in its service territory in southwestern Virginia and southern West Virginia. APCo consolidates Cedar Coal Company, Central Appalachian Coal Company and Southern Appalachian Coal Company, its wholly-owned subsidiaries. APCo sells power at wholesale to municipalities.

In August 2011, APCo purchased the partially completed Dresden Plant at cost of $302 million from AEGCo following approval by the Virginia SCC and the WVPSC. The Dresden Plant is located near Dresden, Ohio and is a natural gas, combined cycle power plant. The Dresden Plant was placed into service in January 2012 and has a generating capacity of 580 MW.

The Interconnection Agreement establishes the AEP Power Pool which permits the AEP East companies to pool their generation assets on a cost basis. It establishes an allocation method for generating capacity among its members based on relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity revenues. AEP Power Pool members are compensated for their costs of energy delivered to the AEP Power Pool and charged for energy received from the AEP Power Pool. The capacity reserve relationship of the AEP Power Pool members changes as generating assets are added, retired or sold and relative peak demand changes. The AEP Power Pool calculates each member's prior twelve-month peak demand relative to the sum of the peak demands of all members as a basis for sharing revenues and costs. The result of this calculation is the MLR, which determines each member's percentage share of revenues and costs. The addition of the Dresden Plant and removal of OPCo's Sporn Unit 5 will change the capacity reserve relationship of the AEP Power Pool members.

The AEP East companies are parties to a Transmission Agreement defining how they share the revenues and costs associated with their relative ownership of transmission assets. This sharing was based upon each company's MLR until the FERC approved a new Transmission Agreement effective November 1, 2010. The impacts of the new Transmission Agreement will be phased-in for retail rates, adds KGPCo and WPCo as parties to the agreement and changes the allocation method.

Under the SIA, AEPSC allocates physical and financial revenues and expenses from transactions with neighboring utilities, power marketers and other power and gas risk management activities based upon the location of such activity, with margins resulting from trading and marketing activities originating in PJM and MISO generally accruing to the benefit of the AEP East companies and trading and marketing activities originating in SPP generally accruing to the benefit of PSO and SWEPCo. Margins resulting from other transactions are allocated among the AEP East companies, PSO and SWEPCo in proportion to the marketing realization directly assigned to each zone for the current month plus the preceding eleven months.

AEPSC conducts power, gas, coal and emission allowance risk management activities on APCo's behalf. APCo shares in the revenues and expenses associated with these risk management activities, as described in the preceding paragraph, with the other AEP East companies, PSO and SWEPCo. Power and gas risk management activities are allocated based on the existing power pool agreement and the SIA. APCo shares in coal and emission allowance risk management activities based on its proportion of fossil fuels burned by the AEP System. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas, coal and emission allowances. The electricity, gas, coal and emission allowance contracts include physical transactions, OTC options and financially-settled swaps and exchange-traded futures and options. AEPSC settles the majority of the physical forward contracts by entering into offsetting contracts.

To minimize the credit requirements and operating constraints when operating within PJM, the AEP East companies as well as KGPCo and WPCo, agreed to a netting of all payment obligations incurred by any of the AEP East companies against all balances due to the AEP East companies and to hold PJM harmless from actions that any one or more AEP East companies may take with respect to PJM.

APCo is jointly and severally liable for activity conducted by AEPSC on behalf of the AEP East companies related to purchase power and sale activity pursuant to the SIA.

Applications to Amend Sharing Agreements

Based upon the PUCO's January 2012 approval of OPCo's corporate separation plan, applications were filed in February 2012 with the FERC proposing to establish a new power cost sharing agreement between APCo, I&M and KPCo and transfer OPCo's generation assets to APCo, KPCo and a nonregulated AEP subsidiary. In conjunction with these filings, APCo and KPCo, which are generation capacity deficit utilities, filed an application with the FERC to acquire approximately 2,400 MWs of OPCo's 12,000 MW generation capacity at net book value. This acquisition would allow APCo and KPCo to satisfy their capacity reserve requirements in PJM and provide baseload generation to meet their customers' energy requirements. The Ohio corporate separation plan was subsequently rejected on rehearing in February 2012. Management is in the process of withdrawing the applications and intends to file new FERC and PUCO applications related to corporate separation.

If APCo experiences decreases in revenues or increases in costs as a result of changes to its relationship with affiliates and is unable to recover the change in revenues and costs through rates, prices or additional sales, it could have an adverse impact on future net income and cash flows.

Regulatory Activity

Virginia Regulatory Activity

In November 2011, the Virginia SCC issued an order which approved a $55 million increase in generation and distribution base rates, effective February 2012, and a 10.9% return on common equity, which included a 0.5% renewable portfolio standards incentive as allowed by law. The $55 million increase included $39 million related to an increase in depreciation rates. See "2011 Virginia Biennial Base Rate Case" section of Note 3.

In January 2012, the Virginia SCC issued an order related to a generation rate adjustment clause which requested recovery of the Dresden Plant costs. The order allows APCo to recover $26 million annually, effective March 2012. See "Rate Adjustment Clauses" section of Note 3.

West Virginia Regulatory Activity

In March 2011, the WVPSC modified and approved a settlement agreement which increased annual base rates by approximately $46 million based upon a 10% return on common equity, effective April 2011. The approved settlement agreement also resulted in a pretax write-off of a portion of the Mountaineer Carbon Capture and Storage Product Validation Facility in March 2011. In addition, the WVPSC allowed APCo to defer and amortize $18 million of previously expensed 2009 incremental storm expenses and $14 million of previously expensed costs related to the 2010 cost reduction initiatives, each over a period of seven years. See "2010 West Virginia Base Rate Case" section of Note 3.

In a November 2009 proceeding established by the WVPSC to explore options to meet WPCo's future power supply requirements, the WVPSC issued an order approving a joint stipulation among APCo, WPCo, the WVPSC staff and the Consumer Advocate Division. The order approved the recommendation of the signatories to the stipulation that WPCo merge into APCo and be supplied from APCo's existing power resources. Merger approvals from the WVPSC, the Virginia SCC and the FERC are required. In December 2011 and February 2012, APCo filed merger applications with the WVPSC and the FERC, respectively. See "WPCo Merger with APCo" section of Note 3.

Litigation and Environmental Issues

In the ordinary course of business, APCo is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot state what the eventual resolution will be or the timing and amount of any loss, fine or penalty may be. Management assesses the probability of loss for each contingency and accrues a liability for cases which have a probable likelihood of loss if the loss can be estimated. For details on regulatory proceedings and pending litigation, see Note 3 – Rate Matters and Note 5 – Commitments, Guarantees and Contingencies. Adverse results in these proceedings have the potential to materially affect net income, financial condition and cash flows.

See the "Executive Overview" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" section beginning on page 375 for additional discussion of relevant factors.

RESULTS OF OPERATIONS

KWH Sales/Degree Days

Summary of KWH Energy Sales

	Years Ended December 31,		
	2011	**2010**	**2009**
	(in millions of KWHs)		
Retail:			
Residential	12,011	13,127	12,218
Commercial	6,915	7,208	6,974
Industrial	10,811	10,774	10,388
Miscellaneous	828	869	835
Total Retail	30,565	31,978	30,415
Wholesale	8,376	6,578	5,648
Total KWHs	38,941	38,556	36,063

Cooling degree days and heating degree days are metrics commonly used in the utility industry as a measure of the impact of weather on net income.

Summary of Heating and Cooling Degree Days

	Years Ended December 31,		
	2011	**2010**	**2009**
	(in degree days)		
Actual - Heating (a)	1,996	2,636	2,214
Normal - Heating (b)	2,267	2,272	2,288
Actual - Cooling (c)	1,432	1,530	1,053
Normal - Cooling (b)	1,186	1,170	1,176

(a) Eastern Region heating degree days are calculated on a 55 degree temperature base.
(b) Normal Heating/Cooling represents the thirty-year average of degree days.
(c) Eastern Region cooling degree days are calculated on a 65 degree temperature base.

2011 Compared to 2010

Reconciliation of Year Ended December 31, 2010 to Year Ended December 31, 2011
Net Income
(in millions)

Year Ended December 31, 2010	$	137
Changes in Gross Margin:		
Retail Margins		(131)
Off-system Sales		2
Transmission Revenues		9
Other Revenues		4
Total Change in Gross Margin		(116)
Changes in Expenses and Other:		
Other Operation and Maintenance		127
Depreciation and Amortization		34
Taxes Other Than Income Taxes		4
Carrying Costs Income		(20)
Other Income		10
Interest Expense		3
Total Change in Expenses and Other		158
Income Tax Expense		(16)
Year Ended December 31, 2011	$	163

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

- **Retail Margins** decreased $131 million primarily due to the following:
  - An $84 million decrease due to the expiration of E&R cost recovery in Virginia.
  - A $47 million decrease in weather-related usage primarily due to a 24% decrease in heating degree days and a 6% decrease in cooling degree days.
  - A $28 million decrease in other variable electric generation expenses.
  - A $24 million write-off in the fourth quarter of 2011 related to the disallowance of certain Virginia environmental costs incurred in 2009 and 2010 as a result of the November 2011 Virginia SCC order.
  - A $24 million decrease in residential and commercial margins primarily due to lower non-weather related usage.

  These decreases were partially offset by:
  - A $53 million increase due to lower capacity settlement expenses under the Interconnection Agreement net of recovery in West Virginia and environmental deferrals in Virginia.
  - A $50 million increase due to higher base rates in West Virginia and Virginia.
  - A $5 million increase primarily due to formula rate increases in Virginia.
- **Transmission Revenues** increased $9 million primarily due to the Transmission Agreement modification effective November 2010.
- **Other Revenues** increased $4 million primarily due to increased gains on emission allowances.

Expenses and Other and Income Tax Expense changed between years as follows:

- **Other Operation and Maintenance** expenses decreased $127 million primarily due to the following:
  - A $54 million decrease due to expenses related to the cost reduction initiatives recorded in 2010.
  - A $54 million decrease due to the second quarter 2010 write-off of the Virginia share of the Mountaineer Carbon Capture and Storage Product Validation Facility as denied for recovery by the Virginia SCC.
  - A $32 million decrease due to the first quarter 2011 deferral of 2010 storm costs and costs related to 2010 cost reduction initiatives. These costs were deferred as a result of the approved modified settlement agreement of APCo's West Virginia base rate case in March 2011.
  - A $27 million decrease due to the favorable fourth quarter 2011 Asset Retirement Obligation adjustment related to the early closure and previous write-off of the Mountaineer Carbon Capture and Storage Product Validation Facility.
  - A $16 million decrease in steam maintenance expenses primarily due to a planned outage at the Amos plant in 2010.
  - A $9 million decrease in transmission expenses primarily due to the expiration of E&R amortization in Virginia.

  These decreases were partially offset by:
  - A $41 million increase due to the first quarter 2011 write-off of a portion of the West Virginia share of the Mountaineer Carbon Capture and Storage Product Validation Facility as denied for recovery by the WVPSC.
  - A $25 million increase due to the second quarter 2010 deferral of 2009 storm costs as allowed by the Virginia SCC.
  - A $19 million increase in transmission expenses primarily due to the Transmission Agreement modification effective November 2010.
  - A $10 million increase in storm-related expenses.
- **Depreciation and Amortization** expenses decreased $34 million primarily due to the expiration of E&R amortization of deferred carrying costs in Virginia, partially offset by an increased depreciation base resulting from environmental upgrades at the Amos Plant.
- **Taxes Other Than Income Taxes** decreased $4 million primarily due to recording a West Virginia franchise tax audit settlement in 2010 and additional employer payroll taxes incurred related to cost reduction initiatives recorded in 2010.
- **Carrying Costs Income** decreased $20 million primarily due to the following:
  - A $15 million decrease due to the expiration of amortization of E&R deferrals in 2010.
  - A $9 million write-off in the fourth quarter of 2011 related to the disallowance of certain Virginia environmental costs as a result of the November 2011 Virginia SCC order.
- **Other Income** increased $10 million primarily due to the following:
  - A $6 million increase due to an increase in the equity component of AFUDC as a result of construction at the Dresden Plant.
  - A $3 million increase due to interest income recorded in the third quarter of 2011 for favorable adjustments related to the 2001-2006 federal income tax audit.
- **Interest Expense** decreased $3 million primarily due to more favorable rates on AFUDC and a reduction in tax-related interest, partially offset by higher line of credit fees.
- **Income Tax Expense** increased $16 million primarily due to an increase in pretax book income and the tax treatment associated with the future reimbursement of Medicare Part D retiree prescription drug benefits, partially offset by the recording of federal and state income tax adjustments resulting from the filing of prior year tax returns.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES, NEW ACCOUNTING PRONOUNCEMENTS

See the "Critical Accounting Policies and Estimates" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" beginning on page 375 for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets and pension and other postretirement benefits.

See the "New Accounting Pronouncements" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" beginning on page 375 for a discussion of the adoption and impact of new accounting pronouncements.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Appalachian Power Company:

We have audited the accompanying consolidated balance sheets of Appalachian Power Company and subsidiaries (the "Company") as of December 31, 2011 and 2010, and the related consolidated statements of income, comprehensive income (loss), changes in common shareholder's equity, and cash flows for each of the three years in the period ended December 31, 2011. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its intemal control over financial reporting. Our audits included consideration of intemal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's intemal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Appalachian Power Company and subsidiaries as of December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, in 2011 the Company changed its method of presenting comprehensive income due to the adoption of FASB Accounting Standards Update No. 2011-05, *Comprehensive Income (Topic 220): Presentation of Comprehensive Income*. The change in presentation has been applied retrospectively to all periods presented.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 28, 2012

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Appalachian Power Company and subsidiaries (APCo) is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. APCo's internal control system was designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of APCo's internal control over financial reporting as of December 31, 2011. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework. Based on management's assessment, APCo's internal control over financial reporting was effective as of December 31, 2011.

This annual report does not include an attestation report of APCo's registered public accounting firm regarding internal control over financial reporting pursuant to the Securities and Exchange Commission rules that permit APCo to provide only management's report in this annual report.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2011, 2010 and 2009
(in thousands)

	2011	2010	2009
REVENUES			
Electric Generation, Transmission and Distribution	$ 2,835,481	$ 2,950,183	$ 2,604,494
Sales to AEP Affiliates	359,802	316,207	263,389
Other Revenues	9,942	8,713	8,772
TOTAL REVENUES	3,205,225	3,275,103	2,876,655
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	759,684	663,422	547,266
Purchased Electricity for Resale	305,647	257,349	246,742
Purchased Electricity from AEP Affiliates	819,182	917,616	803,116
Other Operation	316,995	429,107	266,763
Maintenance	197,002	211,486	274,543
Depreciation and Amortization	270,529	304,192	273,506
Taxes Other Than Income Taxes	106,606	110,908	92,194
TOTAL EXPENSES	2,775,645	2,894,080	2,504,130
OPERATING INCOME	429,580	381,023	372,525
Other Income (Expense):			
Interest Income	5,016	1,477	1,403
Carrying Costs Income	13,433	33,080	22,761
Allowance for Equity Funds Used During Construction	9,212	2,967	7,000
Interest Expense	(204,623)	(207,649)	(202,426)
INCOME BEFORE INCOME TAX EXPENSE	252,618	210,898	201,263
Income Tax Expense	89,860	74,230	45,449
NET INCOME	162,758	136,668	155,814
Preferred Stock Dividend Requirements Including Capital Stock Expense	1,745	900	900
EARNINGS ATTRIBUTABLE TO COMMON STOCK	$ 161,013	$ 135,768	$ 154,914

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

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 225.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2011, 2010 and 2009
(in thousands)

	2011	2010	2009
NET INCOME	$ 162,758	$ 136,668	$ 155,814
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES			
Cash Flow Hedges, Net of Tax of $123 in 2011, $3,843 in 2010 and $970 in 2009	(229)	7,137	(1,801)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $1,674 in 2011, $2,247 in 2010 and $2,642 in 2009	3,109	4,172	4,907
Pension and OPEB Funded Status, Net of Tax of $7,215 in 2011, $4,888 in 2010 and $3,697 in 2009	(13,400)	(9,078)	6,865
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	(10,520)	2,231	9,971
TOTAL COMPREHENSIVE INCOME	$ 152,238	$ 138,899	$ 165,785

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 225.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Years Ended December 31, 2011, 2010 and 2009
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2008	$ 260,458	$ 1,225,292	$ 951,066	$ (60,225)	$ 2,376,591
Capital Contribution from Parent		250,000			250,000
Common Stock Dividends			(20,000)		(20,000)
Preferred Stock Dividends			(799)		(799)
Capital Stock Expense		101	(101)		-
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					2,605,792
NET INCOME			155,814		155,814
OTHER COMPREHENSIVE INCOME				9,971	9,971
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2009	260,458	1,475,393	1,085,980	(50,254)	2,771,577
Common Stock Dividends			(88,000)		(88,000)
Preferred Stock Dividends			(799)		(799)
Capital Stock Expense		103	(101)		2
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					2,682,780
NET INCOME			136,668		136,668
OTHER COMPREHENSIVE INCOME				2,231	2,231
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2010	260,458	1,475,496	1,133,748	(48,023)	2,821,679
Capital Contribution from Parent		100,000			100,000
Common Stock Dividends			(135,000)		(135,000)
Preferred Stock Dividends			(732)		(732)
Loss on Reacquired Preferred Stock		(1,770)			(1,770)
Capital Stock Expense		26	(27)		(1)
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					2,784,176
NET INCOME			162,758		162,758
OTHER COMPREHENSIVE LOSS				(10,520)	(10,520)
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2011	$ 260,458	$ 1,573,752	$ 1,160,747	$ (58,543)	$ 2,936,414

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 225.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2011 and 2010
(in thousands)

	2011	2010
CURRENT ASSETS		
Cash and Cash Equivalents	$ 2,317	$ 951
Advances to Affiliates	22,008	-
Accounts Receivable:		
Customers	158,382	166,878
Affiliated Companies	136,194	145,972
Accrued Unbilled Revenues	68,427	108,210
Miscellaneous	5,505	3,090
Allowance for Uncollectible Accounts	(5,289)	(6,667)
Total Accounts Receivable	363,219	417,483
Fuel	143,931	230,697
Materials and Supplies	101,724	89,370
Risk Management Assets	39,645	53,242
Accrued Tax Benefits	7,715	104,435
Regulatory Asset for Under-Recovered Fuel Costs	41,105	18,300
Prepayments and Other Current Assets	21,745	35,811
TOTAL CURRENT ASSETS	743,409	950,289
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	5,194,967	4,736,150
Transmission	1,943,969	1,852,415
Distribution	2,845,405	2,740,752
Other Property, Plant and Equipment	357,326	348,013
Construction Work in Progress	565,841	562,280
Total Property, Plant and Equipment	10,907,508	10,239,610
Accumulated Depreciation and Amortization	2,994,016	2,843,087
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	7,913,492	7,396,523
OTHER NONCURRENT ASSETS		
Regulatory Assets	1,481,193	1,486,625
Long-term Risk Management Assets	39,226	38,420
Deferred Charges and Other Noncurrent Assets	122,187	125,296
TOTAL OTHER NONCURRENT ASSETS	1,642,606	1,650,341
TOTAL ASSETS	$ 10,299,507	$ 9,997,153

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 225.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
December 31, 2011 and 2010

	2011	2010
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 198,248	$ 128,331
Accounts Payable:		
General	186,612	223,144
Affiliated Companies	137,376	166,884
Long-term Debt Due Within One Year – Nonaffiliated	594,525	479,672
Risk Management Liabilities	26,606	27,993
Customer Deposits	61,690	58,451
Deferred Income Taxes	14,255	44,180
Accrued Taxes	63,422	75,619
Accrued Interest	57,230	57,871
Other Current Liabilities	105,646	93,286
TOTAL CURRENT LIABILITIES	1,445,610	1,355,431
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	3,131,726	3,081,469
Long-term Risk Management Liabilities	12,923	10,873
Deferred Income Taxes	1,736,180	1,642,072
Regulatory Liabilities and Deferred Investment Tax Credits	576,792	562,381
Employee Benefits and Pension Obligations	302,182	306,460
Deferred Credits and Other Noncurrent Liabilities	157,680	199,041
TOTAL NONCURRENT LIABILITIES	5,917,483	5,802,296
TOTAL LIABILITIES	7,363,093	7,157,727
Cumulative Preferred Stock Not Subject to Mandatory Redemption	-	17,747
Rate Matters (Note 3)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 30,000,000 Shares		
Outstanding – 13,499,500 Shares	260,458	260,458
Paid-in Capital	1,573,752	1,475,496
Retained Earnings	1,160,747	1,133,748
Accumulated Other Comprehensive Income (Loss)	(58,543)	(48,023)
TOTAL COMMON SHAREHOLDER'S EQUITY	2,936,414	2,821,679
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 10,299,507	$ 9,997,153

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 225.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2011, 2010 and 2009
(in thousands)

	2011	2010	2009
OPERATING ACTIVITIES			
Net Income	$ 162,758	$ 136,668	$ 155,814
Adjustments to Reconcile Net Income to Net Cash Flows from (Used for) Operating Activities:			
Depreciation and Amortization	270,529	304,192	273,506
Deferred Income Taxes	107,565	144,413	322,626
Carrying Costs Income	(13,433)	(33,080)	(22,761)
Allowance for Equity Funds Used During Construction	(9,212)	(2,967)	(7,000)
Mark-to-Market of Risk Management Contracts	(26)	29,182	(15,346)
Pension Contributions to Qualified Plan Trust	(60,312)	(36,784)	-
Fuel Over/Under-Recovery, Net	(9,589)	(13,356)	(194,436)
Change in Regulatory Assets	(19,355)	38,475	(84,159)
Change in Other Noncurrent Assets	(2,402)	(15,668)	(2,926)
Change in Other Noncurrent Liabilities	10,392	1,757	3,895
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	59,352	(63,426)	(14,489)
Fuel, Materials and Supplies	80,191	116,530	(221,280)
Accounts Payable	(60,843)	(16,823)	(41,370)
Accrued Taxes, Net	71,610	76,881	(172,126)
Other Current Assets	15,570	1,287	(3,608)
Other Current Liabilities	3,933	(11,717)	(5,607)
Net Cash Flows from (Used for) Operating Activities	606,728	655,564	(29,267)
INVESTING ACTIVITIES			
Construction Expenditures	(463,077)	(534,334)	(543,587)
Change in Advances to Affiliates, Net	(22,008)	-	-
Acquisitions of Assets	(302,512)	(2,485)	(1,116)
Other Investing Activities	15,096	12,871	14,745
Net Cash Flows Used for Investing Activities	(772,501)	(523,948)	(529,958)
FINANCING ACTIVITIES			
Capital Contribution from Parent	100,000	-	250,000
Issuance of Long-term Debt – Nonaffiliated	739,393	363,726	447,883
Change in Advances from Affiliates, Net	69,917	(101,215)	34,658
Retirement of Long-term Debt – Nonaffiliated	(579,672)	(200,019)	(150,017)
Retirement of Long-term Debt – Affiliated	-	(100,000)	-
Retirement of Cumulative Preferred Stock	(19,517)	(4)	-
Principal Payments for Capital Lease Obligations	(7,447)	(7,001)	(3,479)
Dividends Paid on Common Stock	(135,000)	(88,000)	(20,000)
Dividends Paid on Cumulative Preferred Stock	(732)	(799)	(799)
Other Financing Activities	197	641	989
Net Cash Flows from (Used for) Financing Activities	167,139	(132,671)	559,235
Net Increase (Decrease) in Cash and Cash Equivalents	1,366	(1,055)	10
Cash and Cash Equivalents at Beginning of Period	951	2,006	1,996
Cash and Cash Equivalents at End of Period	$ 2,317	$ 951	$ 2,006
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 198,465	$ 202,884	$ 209,806
Net Cash Paid (Received) for Income Taxes	(66,520)	(153,205)	(81,508)
Noncash Acquisitions Under Capital Leases	2,692	22,772	2,572
Government Grants Included in Accounts Receivable at December 31,	1,048	1,049	-
Construction Expenditures Included in Current Liabilities at December 31,	65,308	66,048	108,077

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 225.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
INDEX OF NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to APCo's financial statements are combined with the notes to financial statements for other registrant subsidiaries. Listed below are the notes that apply to APCo. The footnotes begin on page 225.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

EXECUTIVE OVERVIEW

Company Overview

As a public utility, I&M engages in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 582,000 retail customers in its service territory in northern and eastern Indiana and a portion of southwestern Michigan. I&M consolidates Blackhawk Coal Company and Price River Coal Company, its wholly-owned subsidiaries. I&M also consolidates DCC Fuel. I&M sells power at wholesale to municipalities and electric cooperatives. I&M's River Transportation Division (RTD) provides barging services to affiliates and nonaffiliated companies. The revenues from barging represent the majority of other revenues except in 2009 when insurance proceeds related to the Cook Plant Unit 1 outage were the largest amount.

The Interconnection Agreement establishes the AEP Power Pool which permits the AEP East companies to pool their generation assets on a cost basis. It establishes an allocation method for generating capacity among its members based on relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity revenues. AEP Power Pool members are compensated for their costs of energy delivered to the AEP Power Pool and charged for energy received from the AEP Power Pool. The capacity reserve relationship of the AEP Power Pool members changes as generating assets are added, retired or sold and relative peak demand changes. The AEP Power Pool calculates each member's prior twelve-month peak demand relative to the sum of the peak demands of all members as a basis for sharing revenues and costs. The result of this calculation is the MLR, which determines each member's percentage share of revenues and costs. APCo's Dresden Plant was completed in January 2012. The addition of the Dresden Plant and removal of OPCo's Sporn Unit 5 will change the capacity reserve relationship of the AEP Power Pool members.

The AEP East companies are parties to a Transmission Agreement defining how they share the revenues and costs associated with their relative ownership of transmission assets. This sharing was based upon each company's MLR until the FERC approved a new Transmission Agreement effective November 1, 2010. The new Transmission Agreement will be phased-in for retail rates over periods of up to four years, adds KGPCo and WPCo as parties to the agreement and changes the allocation method. I&M's recovery mechanism for transmission costs is through its base rates. Changes in allocation under the new Transmission Agreement and state regulatory phase-in of the new agreement will limit I&M's ability to fully recover its transmission costs.

Under unit power agreements, I&M purchases AEGCo's 50% share of the 2,600 MW Rockport Plant capacity unless it is sold to other utilities. AEGCo is an affiliate that is not a member of the AEP Power Pool. An agreement between AEGCo and KPCo provides for the sale of 390 MW of AEGCo's Rockport Plant capacity to KPCo through 2022. Therefore, I&M purchases 910 MW of AEGCo's 50% share of Rockport Plant capacity.

Under the SIA, AEPSC allocates physical and financial revenues and expenses from transactions with neighboring utilities, power marketers and other power and gas risk management activities based upon the location of such activity, with margins resulting from trading and marketing activities originating in PJM and MISO generally accruing to the benefit of the AEP East companies and trading and marketing activities originating in SPP generally accruing to the benefit of PSO and SWEPCo. Margins resulting from other transactions are allocated among the AEP East companies, PSO and SWEPCo in proportion to the marketing realization directly assigned to each zone for the current month plus the preceding eleven months.

AEPSC conducts power, gas, coal and emission allowance risk management activities on I&M's behalf. I&M shares in the revenues and expenses associated with these risk management activities, as described in the preceding paragraph, with the other AEP East companies, PSO and SWEPCo. Power and gas risk management activities are allocated based on the existing power pool agreement and the SIA. I&M shares in coal and emission allowance risk management activities based on its proportion of fossil fuels burned by the AEP System. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas, coal and emission allowances. The electricity, gas, coal and emission allowance contracts include physical transactions, OTC options and financially-settled swaps and exchange-traded futures and options. AEPSC settles the majority of the physical forward contracts by entering into offsetting contracts.

To minimize the credit requirements and operating constraints when operating within PJM, the AEP East companies as well as KGPCo and WPCo, agreed to a netting of all payment obligations incurred by any of the AEP East companies against all balances due to the AEP East companies, and to hold PJM harmless from actions that any one or more AEP East companies may take with respect to PJM.

I&M is jointly and severally liable for activity conducted by AEPSC on behalf of the AEP East companies related to purchase power and sale activity pursuant to the SIA.

Applications to Amend Sharing Agreements

Based upon the PUCO's January 2012 approval of OPCo's corporate separation plan, applications were filed in February 2012 with the FERC proposing to establish a new power cost sharing agreement between APCo, I&M and KPCo and transfer OPCo's generation assets to APCo, KPCo and a nonregulated AEP subsidiary. In conjunction with these filings, APCo and KPCo, which are generation capacity deficit utilities, filed an application with the FERC to acquire approximately 2,400 MWs of OPCo's 12,000 MW generation capacity at net book value. This acquisition would allow APCo and KPCo to satisfy their capacity reserve requirements in PJM and provide baseload generation to meet their customers' energy requirements. The Ohio corporate separation plan was subsequently rejected on rehearing in February 2012. Management is in the process of withdrawing the applications and intends to file new FERC and PUCO applications related to corporate separation.

If I&M experiences decreases in revenues or increases in costs as a result of changes to its relationship with affiliates and is unable to recover the change in revenues and costs through rates, prices or additional sales, it could have an adverse impact on future net income and cash flows.

Regulatory Activity

Michigan Base Rate Case

In July 2011, I&M filed a request with the MPSC for an annual increase in Michigan base rates of $25 million and a return on common equity of 11.15%. The request included an increase in depreciation rates that would result in a $6 million increase in annual depreciation expense. An interim rate increase of $16 million annually was implemented in January 2012, subject to refund.

In February 2012, the MPSC approved a settlement agreement which increased annual base rates by approximately $15 million, effective April 2012, based upon a return on common equity of 10.2% and included a $5 million annual increase in depreciation rates. See "2011 Michigan Base Rate Case" section of Note 3.

Indiana Base Rate Case

In September 2011, I&M filed a request with the IURC for a net annual increase in Indiana base rates of $149 million based upon a return on equity of 11.15%. The request included an increase in depreciation rates that would result in a $25 million increase in annual depreciation expense. See "2011 Indiana Base Rate Case" section of Note 3.

Cook Plant

In September 2008, I&M shut down Cook Plant Unit 1 (Unit 1) due to turbine vibrations, caused by blade failure, which resulted in a fire on the electric generator. Repair of the property damage and replacement of the turbine rotors and other equipment cost approximately $400 million. Management believes that I&M should recover a significant portion of repair and replacement costs through the turbine vendor's warranty, insurance and the regulatory process. Due to the extensive lead time required to manufacture and install new turbine rotors, I&M repaired Unit 1 and it resumed operations in December 2009. The installation of the new turbine rotors and other equipment occurred during the refueling outage of Unit 1 in the fall of 2011. If the ultimate costs of the incident are not covered by warranty, insurance or through the related regulatory process or if any future regulatory proceedings are adverse, it could have an adverse impact on net income, cash flows and financial condition. See "Cook Plant Unit 1 Fire and Shutdown" section of Note 5.

As a result of the nuclear plant situation in Japan following a March 2011 earthquake, the Nuclear Regulatory Commission (NRC) initiated a review of safety procedures and requirements for nuclear generating facilities. This review could increase procedures and testing requirements, require physical modifications to the plant and increase future operating costs at the Cook Plant. The NRC is also looking into the fuel used at eleven reactors, including the units at the Cook Plant. Their concern relates to fuel temperatures if abnormal conditions are experienced. Management has been monitoring this issue and will respond to the NRC's inquiry. In addition to the review by the NRC, Congress could consider legislation tightening oversight of nuclear generating facilities. Management is unable to predict the impact of potential future regulation of nuclear facilities.

Litigation and Environmental Issues

In the ordinary course of business, I&M is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot state what the eventual resolution will be or the timing and amount of any loss, fine or penalty may be. Management assesses the probability of loss for each contingency and accrues a liability for cases which have a probable likelihood of loss if the loss can be estimated. For details on regulatory proceedings and pending litigation, see Note 3 – Rate Matters and Note 5 – Commitments, Guarantees and Contingencies. Adverse results in these proceedings have the potential to materially affect net income, financial condition and cash flows.

See the "Executive Overview" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" section beginning on page 375 for additional discussion of relevant factors.

RESULTS OF OPERATIONS

KWH Sales/Degree Days

Summary of KWH Energy Sales

	Years Ended December 31,		
	2011	2010	2009
	(in millions of KWHs)		
Retail:			
Residential	5,997	6,083	5,767
Commercial	5,045	5,121	5,038
Industrial	7,523	7,445	6,762
Miscellaneous	73	72	76
Total Retail	18,638	18,721	17,643
Wholesale	9,249	7,839	8,564
Total KWHs	27,887	26,560	26,207

Cooling degree days and heating degree days are metrics commonly used in the utility industry as a measure of the impact of weather on net income.

Summary of Heating and Cooling Degree Days

	Years Ended December 31,		
	2011	**2010**	**2009**
		(in degree days)	
Actual - Heating (a)	3,659	3,759	3,876
Normal - Heating (b)	3,766	3,774	3,788
Actual - Cooling (c)	1,075	1,165	580
Normal - Cooling (b)	848	832	844

(a) Eastern Region heating degree days are calculated on a 55 degree temperature base.
(b) Normal Heating/Cooling represents the thirty-year average of degree days.
(c) Eastern Region cooling degree days are calculated on a 65 degree temperature base.

2011 Compared to 2010

Reconciliation of Year Ended December 31, 2010 to Year Ended December 31, 2011
Net Income
(in millions)

Year Ended December 31, 2010	$	126
Changes in Gross Margin:		
Retail Margins		(13)
FERC Municipals and Cooperatives		3
Off-system Sales		2
Transmission Revenues		(1)
Other Revenues		2
Total Change in Gross Margin		(7)
Changes in Expenses and Other:		
Other Operation and Maintenance		12
Depreciation and Amortization		3
Taxes Other Than Income Taxes		(2)
Other Income		(1)
Interest Expense		7
Total Change in Expenses and Other		19
Income Tax Expense		12
Year Ended December 31, 2011	$	150

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

- **Retail Margins** decreased $13 million primarily due to the following:
  - A $29 million decrease in capacity settlements under the Interconnection Agreement.
  - A $14 million decrease due to customer credits for a settlement relating to the Cook Plant Unit 1 (Unit 1) fire outage. This decrease was offset by a decrease in Other Operation and Maintenance expenses.

  These decreases were partially offset by:
  - A $27 million increase due to rate relief primarily from the Michigan rate increase effective in 2010 and recovery of costs through trackers.

Expenses and Other and Income Tax Expense changed between years as follows:

- **Other Operation and Maintenance** expenses decreased $12 million primarily due to the following:
  - A $35 million decrease due to expenses related to the cost reduction initiatives recorded in 2010.
  - A $14 million decrease in steam power expenses relating to the Unit 1 fire outage. This decrease was offset by a decrease in Retail Margins.

  These decreases were partially offset by:
  - A $25 million increase in transmission expense primarily due to the Transmission Agreement modification effective November 2010.
  - A $9 million increase in customer service costs associated with higher demand side management expenses. This increase is offset by an increase in Retail Margins above.
- **Interest Expense** decreased $7 million primarily due to lower outstanding debt.
- **Income Tax Expense** decreased $12 million primarily due to the recording of federal and state income tax adjustments resulting from the filing of prior year tax returns and other book/tax differences which are accounted for on a flow-through basis, partially offset by an increase in pretax book income.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES, NEW ACCOUNTING PRONOUNCEMENTS

See the "Critical Accounting Policies and Estimates" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" beginning on page 375 for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets and pension and other postretirement benefits.

See the "New Accounting Pronouncements" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" beginning on page 375 for a discussion of the adoption and impact of new accounting pronouncements.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Indiana Michigan Power Company:

We have audited the accompanying consolidated balance sheets of Indiana Michigan Power Company and subsidiaries (the "Company") as of December 31, 2011 and 2010, and the related consolidated statements of income, comprehensive income (loss), changes in common shareholder's equity, and cash flows for each of the three years in the period ended December 31, 2011. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Indiana Michigan Power Company and subsidiaries as of December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, in 2011 the Company changed its method of presenting comprehensive income due to the adoption of FASB Accounting Standards Update No. 2011-05, *Comprehensive Income (Topic 220): Presentation of Comprehensive Income.* The change in presentation has been applied retrospectively to all periods presented.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 28, 2012

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Indiana Michigan Power Company and subsidiaries (I&M) is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. I&M's internal control system was designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of I&M's internal control over financial reporting as of December 31, 2011. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework. Based on management's assessment, I&M's internal control over financial reporting was effective as of December 31, 2011.

This annual report does not include an attestation report of I&M's registered public accounting firm regarding internal control over financial reporting pursuant to the Securities and Exchange Commission rules that permit I&M to provide only management's report in this annual report.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2011, 2010 and 2009
(in thousands)

	2011	2010	2009
REVENUES			
Electric Generation, Transmission and Distribution	$ 1,770,447	$ 1,735,338	$ 1,685,308
Sales to AEP Affiliates	320,184	330,951	196,151
Other Revenues - Affiliated	109,053	114,070	110,143
Other Revenues - Nonaffiliated	15,086	15,368	193,422
TOTAL REVENUES	2,214,770	2,195,727	2,185,024
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	472,080	465,482	409,845
Purchased Electricity for Resale	121,375	128,369	128,508
Purchased Electricity from AEP Affiliates	353,484	327,335	337,308
Other Operation	540,595	560,346	500,672
Maintenance	229,883	222,406	218,036
Depreciation and Amortization	133,394	136,443	134,690
Taxes Other Than Income Taxes	82,303	80,431	75,262
TOTAL EXPENSES	1,933,114	1,920,812	1,804,321
OPERATING INCOME	281,656	274,915	380,703
Other Income (Expense):			
Interest Income	2,048	3,389	5,776
Allowance for Equity Funds Used During Construction	15,395	15,678	12,013
Interest Expense	(97,665)	(104,465)	(101,145)
INCOME BEFORE INCOME TAX EXPENSE	201,434	189,517	297,347
Income Tax Expense	51,760	63,426	81,037
NET INCOME	149,674	126,091	216,310
Preferred Stock Dividend Requirements Including Capital Stock Expense	626	339	339
EARNINGS ATTRIBUTABLE TO COMMON STOCK	$ 149,048	$ 125,752	$ 215,971

The common stock of I&M is wholly-owned by AEP.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 225.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2011, 2010 and 2009
(in thousands)

	2011	2010	2009
NET INCOME	$ 149,674	$ 126,091	$ 216,310
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES			
Cash Flow Hedges, Net of Tax of $3,553 in 2011, $652 in 2010 and $462 in 2009	(6,599)	1,211	(857)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $510 in 2011, $470 in 2010 and $445 in 2009	948	873	826
Pension and OPEB Funded Status, Net of Tax of $906 in 2011, $685 in 2010 and $13 in 2009	(1,681)	(1,272)	24
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	(7,332)	812	(7)
TOTAL COMPREHENSIVE INCOME	$ 142,342	$ 126,903	$ 216,303

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 225.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Years Ended December 31, 2011, 2010 and 2009
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2008	$ 56,584	$ 861,291	$ 538,637	$ (21,694)	$ 1,434,818
Capital Contribution from Parent		120,000			120,000
Common Stock Dividends			(98,000)		(98,000)
Preferred Stock Dividends			(339)		(339)
Gain on Reacquired Preferred Stock		1			1
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					1,456,480
NET INCOME			216,310		216,310
OTHER COMPREHENSIVE LOSS				(7)	(7)
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2009	56,584	981,292	656,608	(21,701)	1,672,783
Common Stock Dividends			(105,000)		(105,000)
Preferred Stock Dividends			(339)		(339)
Gain on Reacquired Preferred Stock		2			2
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					1,567,446
NET INCOME			126,091		126,091
OTHER COMPREHENSIVE INCOME				812	812
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2010	56,584	981,294	677,360	(20,889)	1,694,349
Common Stock Dividends			(75,000)		(75,000)
Preferred Stock Dividends			(313)		(313)
Loss on Reacquired Preferred Stock		(398)			(398)
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					1,618,638
NET INCOME			149,674		149,674
OTHER COMPREHENSIVE LOSS				(7,332)	(7,332)
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2011	$ 56,584	$ 980,896	$ 751,721	$ (28,221)	$ 1,760,980

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 225.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2011 and 2010
(in thousands)

	2011	2010
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,020	$ 361
Advances to Affiliates	95,714	-
Accounts Receivable:		
Customers	72,461	76,193
Affiliated Companies	90,980	149,169
Accrued Unbilled Revenues	14,780	19,449
Miscellaneous	22,685	10,968
Allowance for Uncollectible Accounts	(1,750)	(1,692)
Total Accounts Receivable	199,156	254,087
Fuel	52,979	87,551
Materials and Supplies	175,924	178,331
Risk Management Assets	32,152	27,526
Accrued Tax Benefits	38,425	71,113
Deferred Cook Plant Fire Costs	63,809	45,752
Prepayments and Other Current Assets	35,395	33,713
TOTAL CURRENT ASSETS	694,574	698,434
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	3,932,472	3,774,262
Transmission	1,224,786	1,188,665
Distribution	1,481,608	1,411,095
Other Property, Plant and Equipment (including nuclear fuel and coal mining)	709,558	719,708
Construction Work in Progress	236,096	301,534
Total Property, Plant and Equipment	7,584,520	7,395,264
Accumulated Depreciation, Depletion and Amortization	3,179,920	3,124,998
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	4,404,600	4,270,266
OTHER NONCURRENT ASSETS		
Regulatory Assets	602,979	556,254
Spent Nuclear Fuel and Decommissioning Trusts	1,591,732	1,515,227
Long-term Risk Management Assets	29,362	31,485
Deferred Charges and Other Noncurrent Assets	69,309	77,229
TOTAL OTHER NONCURRENT ASSETS	2,293,382	2,180,195
TOTAL ASSETS	$ 7,392,556	$ 7,148,895

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 225.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
December 31, 2011 and 2010
(dollars in thousands)

	2011	2010
CURRENT LIABILITIES		
Advances from Affiliates	$ -	$ 42,769
Accounts Payable:		
General	113,063	121,665
Affiliated Companies	81,102	105,221
Long-term Debt Due Within One Year – Nonaffiliated (December 31, 2011 and 2010 amount includes $101,620 and $77,457, respectively, related to DCC Fuel)	279,075	154,457
Risk Management Liabilities	16,980	16,785
Customer Deposits	30,696	29,264
Accrued Taxes	65,233	62,637
Accrued Interest	27,798	27,444
Other Current Liabilities	117,879	140,710
TOTAL CURRENT LIABILITIES	731,826	700,952
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,778,600	1,849,769
Long-term Risk Management Liabilities	18,871	6,530
Deferred Income Taxes	925,712	760,105
Regulatory Liabilities and Deferred Investment Tax Credits	875,202	852,197
Asset Retirement Obligations	1,013,122	963,029
Deferred Credits and Other Noncurrent Liabilities	288,243	313,892
TOTAL NONCURRENT LIABILITIES	4,899,750	4,745,522
TOTAL LIABILITIES	5,631,576	5,446,474
Cumulative Preferred Stock Not Subject to Mandatory Redemption	-	8,072
Rate Matters (Note 3)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 2,500,000 Shares		
Outstanding – 1,400,000 Shares	56,584	56,584
Paid-in Capital	980,896	981,294
Retained Earnings	751,721	677,360
Accumulated Other Comprehensive Income (Loss)	(28,221)	(20,889)
TOTAL COMMON SHAREHOLDER'S EQUITY	1,760,980	1,694,349
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 7,392,556	$ 7,148,895

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 225.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2011, 2010 and 2009
(in thousands)

	2011	2010	2009
OPERATING ACTIVITIES			
Net Income	$ 149,674	$ 126,091	$ 216,310
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	133,394	136,443	134,690
Accretion of Asset Retirement Obligations	11,668	11,905	11,178
Deferred Income Taxes	141,015	63,947	271,264
Amortization (Deferral) of Incremental Nuclear Refueling Outage Expenses, Net	13,244	(31,939)	3,110
Allowance for Equity Funds Used During Construction	(15,395)	(15,678)	(12,013)
Mark-to-Market of Risk Management Contracts	(1,590)	4,592	(10,533)
Amortization of Nuclear Fuel	136,707	139,438	62,699
Pension Contributions to Qualified Plan Trust	(52,588)	(71,681)	-
Fuel Over/Under Recovery, Net	(13,885)	(12,589)	34,676
Change in Other Noncurrent Assets	(22,977)	(12,597)	(16,555)
Change in Other Noncurrent Liabilities	50,371	56,592	45,276
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	57,661	(85,072)	19,338
Fuel, Materials and Supplies	40,239	(16,564)	(20,676)
Accounts Payable	(52,175)	46,579	(65,424)
Accrued Taxes, Net	15,508	77,075	(132,214)
Cook Plant Fire Costs, Net	18,282	87,347	(89,409)
Other Current Assets	6,409	5,056	(5,351)
Other Current Liabilities	6,167	4,149	(2,924)
Net Cash Flows from Operating Activities	621,729	513,094	443,442
INVESTING ACTIVITIES			
Construction Expenditures	(301,242)	(333,238)	(332,775)
Change in Advances to Affiliates, Net	(95,714)	114,012	(114,012)
Purchases of Investment Securities	(1,166,690)	(1,414,473)	(770,919)
Sales of Investment Securities	1,110,909	1,361,813	712,742
Acquisitions of Nuclear Fuel	(105,703)	(90,903)	(169,138)
Other Investing Activities	47,169	17,105	21,004
Net Cash Flows Used for Investing Activities	(511,271)	(345,684)	(653,098)
FINANCING ACTIVITIES			
Capital Contribution from Parent	-	-	120,000
Issuance of Long-term Debt - Nonaffiliated	185,972	152,464	670,060
Issuance of Long-term Debt - Affiliated	-	-	25,000
Change in Advances from Affiliates, Net	(42,769)	42,769	(476,036)
Retirement of Long-term Debt - Nonaffiliated	(160,645)	(202,011)	-
Retirement of Long-term Debt - Affiliated	-	(25,000)	-
Retirement of Cumulative Preferred Stock	(8,470)	(3)	(2)
Principal Payments for Capital Lease Obligations	(8,652)	(31,180)	(31,637)
Dividends Paid on Common Stock	(75,000)	(105,000)	(98,000)
Dividends Paid on Cumulative Preferred Stock	(313)	(339)	(339)
Other Financing Activities	78	472	661
Net Cash Flows from (Used for) Financing Activities	(109,799)	(167,828)	209,707
Net Increase (Decrease) in Cash and Cash Equivalents	659	(418)	51
Cash and Cash Equivalents at Beginning of Period	361	779	728
Cash and Cash Equivalents at End of Period	$ 1,020	$ 361	$ 779
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 95,124	$ 100,617	$ 99,079
Net Cash Paid (Received) for Income Taxes	(96,452)	(71,268)	(51,298)
Noncash Acquisitions Under Capital Leases	3,454	10,000	2,651
Construction Expenditures Included in Current Liabilities at December 31,	42,992	21,757	74,251
Acquisition of Nuclear Fuel Included in Current Liabilities at December 31,	715	308	15
Noncash Increase in Long-term Debt Through the Fort Wayne Lease Settlement	26,802	-	-

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 225.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
INDEX OF NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to I&M's financial statements are combined with the notes to financial statements for other registrant subsidiaries. Listed below are the notes that apply to I&M. The footnotes begin on page 225.

OHIO POWER COMPANY CONSOLIDATED
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

EXECUTIVE OVERVIEW

Company Overview

As a public utility, OPCo engages in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 1,460,000 retail customers in the northwestern, central, eastern and southern sections of Ohio. OPCo consolidates Conesville Coal Preparation Company, its wholly-owned subsidiary. OPCo consolidated JMG Funding LP, a variable interest entity, until it was dissolved in December 2009 at which time JMG's assets were transferred to OPCo.

The Interconnection Agreement establishes the AEP Power Pool which permits the AEP East companies to pool their generation assets on a cost basis. It establishes an allocation method for generating capacity among its members based on relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity revenues. AEP Power Pool members are compensated for their costs of energy delivered to the AEP Power Pool and charged for energy received from the AEP Power Pool. The capacity reserve relationship of the AEP Power Pool members changes as generating assets are added, retired or sold and relative peak demand changes. The AEP Power Pool calculates each member's prior twelve-month peak demand relative to the sum of the peak demands of all members as a basis for sharing revenues and costs. The result of this calculation is the MLR, which determines each member's percentage share of revenues and costs. APCo's Dresden Plant was completed in January 2012. The addition of the Dresden Plant and removal of OPCo's Sporn Unit 5 will change the capacity reserve relationship of the AEP Power Pool members.

The AEP East companies are parties to a Transmission Agreement defining how they share the revenues and costs associated with their relative ownership of transmission assets. This sharing was based upon each company's MLR until the FERC approved a new Transmission Agreement effective November 1, 2010. The impacts of the new Transmission Agreement will be phased-in for retail rates, adds KGPCo and WPCo as parties to the agreement and changes the allocation method.

In 2007, OPCo and AEGCo entered into a 10-year unit power agreement for the entire output from the Lawrenceburg Plant with an option for an additional 2-year period. OPCo pays AEGCo for the capacity, depreciation, fuel, operation and maintenance and tax expenses. These payments are due regardless of whether the plant operates.

Under the SIA, AEPSC allocates physical and financial revenues and expenses from transactions with neighboring utilities, power marketers and other power and gas risk management activities based upon the location of such activity, with margins resulting from trading and marketing activities originating in PJM and MISO generally accruing to the benefit of the AEP East companies and trading and marketing activities originating in SPP generally accruing to the benefit of PSO and SWEPCo. Margins resulting from other transactions are allocated among the AEP East companies, PSO and SWEPCo in proportion to the marketing realization directly assigned to each zone for the current month plus the preceding eleven months.

AEPSC conducts power, gas, coal and emission allowance risk management activities on OPCo's behalf. OPCo shares in the revenues and expenses associated with these risk management activities, as described in the preceding paragraph, with the other AEP East companies, PSO and SWEPCo. Power and gas risk management activities are allocated based on the existing power pool agreement and the SIA. OPCo shares in coal and emission allowance risk management activities based on its proportion of fossil fuels burned by the AEP System. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas, coal and emission allowances. The electricity, gas, coal and emission allowance contracts include physical transactions, OTC options and financially-settled swaps and exchange-traded futures and options. AEPSC settles the majority of the physical forward contracts by entering into offsetting contracts.

To minimize the credit requirements and operating constraints of operating within PJM, the AEP East companies as well as KGPCo and WPCo, agreed to a netting of all payment obligations incurred by any of the AEP East companies against all balances due to the AEP East companies and to hold PJM harmless from actions that any one or more AEP East companies may take with respect to PJM.

OPCo is jointly and severally liable for activity conducted by AEPSC on behalf of the AEP East companies related to purchase power and sale activity pursuant to the SIA.

CSPCo-OPCo Merger

On December 31, 2011, CSPCo merged into OPCo with OPCo being the surviving entity. All prior reported amounts have been recast as if the merger occurred on the first day of the earliest reporting period. All contracts and operations of CSPCo and its subsidiary are now part of OPCo.

January 2012 – May 2016 ESP

In December 2011, the PUCO approved a modified stipulation for a new ESP for the period January 2012 through May 2016 that includes a standard service offer (SSO) pricing for generation. Various parties, including OPCo, filed requests for rehearing with the PUCO. In February 2012, the PUCO issued an entry on rehearing which rejected the modified stipulation and ordered a return to the 2011 ESP rates until a new rate plan is approved. Under the February 2012 rehearing order, OPCo has 30 days to notify the PUCO whether it plans to modify or withdraw its original application as filed in January 2011. Management is currently evaluating its options and the potential financial and operational impacts on OPCo. See "Ohio Electric Security Plan Filing" section of Note 3.

Ohio Customer Choice

In OPCo's service territory, various competitive retail electric service (CRES) providers are targeting retail customers by offering alternative generation service. As a result, in comparison to 2010, OPCo lost approximately $132 million of generation and transmission related gross margin. OPCo is recovering a portion of lost margins through collection of capacity and transmission revenues from competitive CRES providers and off-system sales. As a result of the February 2012 order on rehearing, OPCo is subject to significant risk of revenue loss associated with customer switching, which could materially reduce future net income and cash flows and materially impact financial condition. Currently, there are no limitations on the obligation of OPCo to provide below cost capacity rate pricing to alternative suppliers to support customers switching in Ohio. As a result of customer switching, for every 10% decline in the number of retail customers, management estimates OPCo could lose approximately $75 million of generation gross margin, net of estimated off-system sales. On February 27, 2012, OPCo filed a Motion for Relief and Request for Expedited Ruling with the PUCO related to the review of capacity charges. The filing seeks a decision within 90 days and the avoidance of an immediate change to pricing for capacity at the Reliability Pricing Model auction price, which is substantially below OPCo's cost. Management is evaluating its options to challenge this capacity pricing issue.

Corporate Separation

In January 2012, the PUCO approved a corporate separation plan of OPCo's generation assets to complete the transition to a fully competitive generation market by June 2015, which includes the transfer of generation assets to a nonregulated AEP subsidiary at net book value. In February 2012, as part of the PUCO's entry on rehearing which rejected the ESP modified stipulation, the PUCO revoked its approval of OPCo's corporate separation plan. Any proposed corporate separation plan will require approval by the PUCO and the FERC. Management intends to pursue Ohio corporate separation in future regulatory proceedings.

In February 2012, prior to the PUCO revoking OPCo's corporate separation plan, applications were filed with the FERC proposing to establish a new power cost sharing agreement between APCo, I&M and KPCo and transfer OPCo's generation assets to APCo, KPCo and a nonregulated AEP subsidiary. In conjunction with these filings, APCo and KPCo, which are generation capacity deficit utilities, filed an application with the FERC to acquire approximately 2,400 MWs of OPCo's 12,000 MW generation capacity at net book value. This acquisition would allow APCo and KPCo to satisfy their capacity reserve requirements in PJM and provide baseload generation to meet their customers' energy requirements. As a result of the February 2012 ESP rehearing order, management is reviewing the recoverability of all OPCo generation assets and is in the process of withdrawing the PUCO and the FERC applications. Management intends to file new FERC and PUCO applications related to corporate separation. To the extent existing generation assets and the cost of new equipment and converted facilities are not recoverable, it could materially reduce future net income and cash flows. Upon receipt of all regulatory approvals, the remaining generation assets of OPCo will be owned by a nonregulated AEP subsidiary.

If OPCo receives all regulatory approvals without authority to transfer its generation, OPCo's results of operations related to generation will be determined by its ability to sell power and capacity at a profit at rates determined by the prevailing market. If OPCo experiences decreases in revenues or increases in costs as a result of changes to its relationship with affiliates and is unable to recover the change in revenues and costs through rates, prices or additional sales, it could have an adverse impact on future net income and cash flows.

Regulatory Activity

2009 – 2011 ESP

In 2011, the PUCO issued an order in the 2009 – 2011 ESP remand proceeding requiring OPCo to cease POLR billings and apply POLR collections since June 2011 first to the FAC deferral with any remaining balance to be credited to OPCo's customers in November and December 2011. As a result, in comparison to 2010, we lost approximately $71 million of pretax income related to POLR. In February 2012, the Ohio Consumers' Counsel (OCC) and the Industrial Energy Users-Ohio filed appeals with the Supreme Court of Ohio challenging various issues, including the PUCO's refusal to order retrospective relief concerning the POLR charges collected during 2009 – 2011 and various aspects of the approved environmental carrying charge, which if ordered could total up to $698 million, excluding carrying costs.

OPCo filed its 2010 Significantly Excessive Earnings Test (SEET) with the PUCO based upon the approach in the PUCO's 2009 order. Subsequent testimony and legal briefs from intervenors recommended a refund of up to $62 million of 2010 earnings, which included off-system sales in the SEET calculation. In December 2011, the PUCO staff filed testimony that recommended a $23 million refund of 2010 earnings. In the fourth quarter of 2011, OPCo provided a reserve based upon management's estimate of the probable amount for a PUCO ordered SEET refund. OPCo is required to file its 2011 SEET filing with the PUCO in 2012. Management does not currently believe that there are significantly excessive earnings in 2011. See "Ohio Electric Security Plan Filing" section of Note 3.

Ohio Distribution Base Rate Case

In December 2011, a stipulation was approved by the PUCO which provided for no change in distribution rates and a new rider for a $15 million annual credit to residential ratepayers due principally to the inclusion of the rate base distribution investment in the Distribution Investment Rider (DIR). The stipulation also approved recovery of certain distribution regulatory assets of $173 million as of December 31, 2011, excluding $154 million of unrecognized equity carrying costs. These assets and unrecognized carrying costs will be recovered in a distribution asset recovery rider over seven years with an additional long term debt carrying charge, effective January 2012.

Due to the February 2012 PUCO ESP entry on rehearing which rejected the modified stipulation for a new ESP, collection of the DIR terminated. OPCo has the right to withdraw from the stipulation in the distribution base rate case. Management is currently evaluating all its options. See "2011 Ohio Distribution Base Rate Case" section of Note 3.

Litigation and Environmental Issues

In the ordinary course of business, OPCo is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot state what the eventual resolution will be or the timing and amount of any loss, fine or penalty may be. Management assesses the probability of loss for each contingency and accrues a liability for cases which have a probable likelihood of loss if the loss can be estimated. For details on regulatory proceedings and pending litigation, see Note 3 – Rate Matters and Note 5 – Commitments, Guarantees and Contingencies. Adverse results in these proceedings have the potential to materially affect net income, financial condition and cash flows.

See the "Executive Overview" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" section beginning on page 375 for additional discussion of relevant factors.

RESULTS OF OPERATIONS

KWH Sales/Degree Days

Summary of KWH Energy Sales

	Years Ended December 31,		
	2011	2010	2009
	(in millions of KWHs)		
Retail:			
Residential	15,082	15,386	14,642
Commercial	14,269	14,454	14,218
Industrial	18,946	17,455	16,605
Miscellaneous	123	129	131
Total Retail	48,420	47,424	45,596
Wholesale	12,229	8,466	6,958
Total KWHs	60,649	55,890	52,554

Cooling degree days and heating degree days are metrics commonly used in the utility industry as a measure of the impact of weather on net income.

Summary of Heating and Cooling Degree Days

	Years Ended December 31,		
	2011	2010	2009
	(in degree days)		
Actual - Heating (a)	3,107	3,488	3,336
Normal - Heating (b)	3,266	3,267	3,280
Actual - Cooling (c)	1,112	1,189	721
Normal - Cooling (b)	936	921	931

(a) Eastern Region heating degree days are calculated on a 55 degree temperature base.
(b) Normal Heating/Cooling represents the thirty-year average of degree days.
(c) Eastern Region cooling degree days are calculated on a 65 degree temperature base.

2011 Compared to 2010

Reconciliation of Year Ended December 31, 2010 to Year Ended December 31, 2011
Net Income
(in millions)

Year Ended December 31, 2010	$ 542
Changes in Gross Margin:	
Retail Margins	(146)
Off-system Sales	49
Transmission Revenues	20
Other Revenues	1
Total Change in Gross Margin	(76)
Changes in Expenses and Other:	
Other Operation and Maintenance	(6)
Asset Impairments and Other Related Charges	(90)
Depreciation and Amortization	(32)
Taxes Other Than Income Taxes	(6)
Carrying Costs Income	22
Other Income	4
Interest Expense	20
Total Change in Expenses and Other	(88)
Income Tax Expense	87
Year Ended December 31, 2011	$ 465

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

- **Retail Margins** decreased $146 million primarily due to the following:
  - A $132 million decrease attributable to customers switching to alternative competitive retail electric service (CRES) providers.
  - A $60 million decrease due to the elimination of POLR charges, effective June 2011, as a result of the October 2011 PUCO remand order.
  - A $42 million net decrease due to unfavorable regulatory orders in 2011 and 2010.
  - A $29 million decrease in capacity settlements under the Interconnection Agreement.
  - A $23 million decrease in weather-related usage primarily due to an 11% decrease in heating degree days and a 7% decrease in cooling degree days.

  These decreases were partially offset by:
  - A $39 million increase in revenues due to the implementation of PUCO rider rates related to Environmental Investment Carrying Charge Rider revenues.
  - A $38 million increase in revenue due to the implementation of PUCO approved rider rates in June 2010 related to the Energy Efficiency & Peak Demand Reduction (EE/PDR) Programs. This increase in Retail Margins was offset by increases in Other Operation and Maintenance as discussed below.
  - A $29 million increase due to sales to Buckeye Power, Inc. to provide backup energy under the Cardinal Station Agreement.
  - A $20 million increase in revenues due to a January 2011 Universal Service Fund (USF) surcharge rate increase. This increase in Retail Margins was offset by a corresponding increase in Other Operation and Maintenance as discussed below.
  - An $18 million net increase in transmission rider revenues.
- **Margins from Off-system Sales** increased $49 million primarily due to an increase in PJM capacity revenues and higher physical sales volumes, partially offset by lower trading and marketing margins.

- **Transmission Revenues** increased $20 million primarily due to the Transmission Agreement modification effective November 2010, a portion of which is included in the Ohio Transmission Cost Recovery Rider and increased transmission revenues for customers who have switched to alternative CRES providers. The increase in transmission revenues related to CRES providers offsets lost revenues included in Retail Margins above.

Expenses and Other and Income Tax Expense changed between years as follows:

- **Other Operation and Maintenance** expenses increased $6 million primarily due to:
  - A $50 million increase in plant maintenance expense primarily related to work performed at the Kammer, Amos, Conesville and Mitchell plants.
  - A $40 million increase in expenses due to the implementation of PUCO approved EE/PDR programs. This increase in Other Operation and Maintenance expense was partially offset by an increase in Retail Margins as discussed above.
  - A $35 million increase related to the fourth quarter 2011 recording of an obligation to contribute to Partnership with Ohio and Ohio Growth Fund as a result of the approved December 2011 Ohio stipulation agreement.
  - A $21 million increase in remitted USF surcharge payments to the Ohio Department of Development to fund an energy assistance program for qualified Ohio customers. This increase in Other Operation and Maintenance expense was offset by a corresponding increase in Retail Margins as discussed above.
  - A $9 million increase primarily due to removal costs at the Cardinal and Amos plants.
  - An $8 million increase in expenses related to Cook Coal Terminal.
  - A $6 million increase due to the 2011 write-off of Front-End Engineering and Design (FEED) study costs related to the Mountaineer Carbon Capture Project.

  These increases were partially offset by:
  - An $85 million decrease due to expenses related to the cost reduction initiatives recorded in 2010.
  - A $36 million decrease in transmission expense primarily due to the Transmission Agreement modification effective November 2010, a portion of which is included in the Ohio Transmission Cost Recovery Rider.
  - A $28 million decrease in recoverable PJM expenses.
  - An $11 million gain from the sale of land in January 2011.
- **Asset Impairments and Other Related Charges** includes the third quarter 2011 plant impairments of Sporn Unit 5 ($48 million) and the FGD project at Muskingum River Unit 5 ($42 million).
- **Depreciation and Amortization** increased $32 million primarily due to:
  - A $23 million increase due to the amortization of carrying costs on deferred fuel as a result of the October 2011 POLR remand order.
  - A $6 million increase due to higher depreciable property balances as a result of environmental and various other property additions.
  - A $4 million increase as a result of accelerated depreciation on various plants beginning in the fourth quarter of 2011.
- **Taxes Other Than Income Taxes** increased $6 million primarily due to an $8 million increase in real and property taxes, partially offset by a $3 million decrease due to the employer portion of payroll taxes incurred related to cost reduction initiatives recorded in 2010.
- **Carrying Costs Income** increased $22 million primarily due to a higher under-recovered fuel balance in 2011.
- **Interest Expense** decreased $20 million primarily due to the retirement of long-term debt in the fourth quarter of 2010.
- **Income Tax Expense** decreased $87 million primarily due to a decrease in pretax book income, the recording of federal and state income tax adjustments resulting from the filing of prior year tax returns and the tax treatment associated with the future reimbursement of Medicare Part D retiree prescription drug benefits.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES, NEW ACCOUNTING PRONOUNCEMENTS

See the "Critical Accounting Policies and Estimates" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" beginning on page 375 for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets and pension and other postretirement benefits.

See the "New Accounting Pronouncements" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" beginning on page 375 for a discussion of the adoption and impact of new accounting pronouncements.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Ohio Power Company:

We have audited the accompanying consolidated balance sheets of Ohio Power Company Consolidated (the "Company") as of December 31, 2011 and 2010, and the related consolidated statements of income, comprehensive income (loss), changes in equity, and cash flows for each of the three years in the period ended December 31, 2011. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Ohio Power Company Consolidated as of December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, in 2011 the Company changed its method of presenting comprehensive income due to the adoption of FASB Accounting Standards Update No. 2011-05, *Comprehensive Income (Topic 220): Presentation of Comprehensive Income.* The change in presentation has been applied retrospectively to all periods presented.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 28, 2012

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Ohio Power Company Consolidated (OPCo) is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. OPCo's internal control system was designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of OPCo's internal control over financial reporting as of December 31, 2011. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework. Based on management's assessment, OPCo's internal control over financial reporting was effective as of December 31, 2011.

This annual report does not include an attestation report of OPCo's registered public accounting firm regarding internal control over financial reporting pursuant to the Securities and Exchange Commission rules that permit OPCo to provide only management's report in this annual report.

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2011, 2010 and 2009
(in thousands)

	2011	2010	2009
REVENUES			
Electric Generation, Transmission and Distribution	$ 4,406,814	$ 4,222,461	$ 3,875,595
Sales to AEP Affiliates	977,999	991,285	921,089
Other Revenues - Affiliated	27,903	21,069	23,457
Other Revenues - Nonaffiliated	18,395	20,301	15,592
TOTAL REVENUES	5,431,111	5,255,116	4,835,733
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	1,597,410	1,488,474	1,286,718
Purchased Electricity for Resale	300,653	286,835	263,385
Purchased Electricity from AEP Affiliates	515,613	386,618	288,115
Other Operation	754,109	795,129	675,785
Maintenance	393,943	346,745	350,880
Asset Impairments and Other Related Charges	89,824	-	-
Depreciation and Amortization	545,376	513,168	496,470
Taxes Other Than Income Taxes	399,479	393,537	369,461
TOTAL EXPENSES	4,596,407	4,210,506	3,730,814
OPERATING INCOME	834,704	1,044,610	1,104,919
Other Income (Expense):			
Interest Income	7,069	2,567	2,238
Carrying Costs Income	53,345	31,796	18,354
Allowance for Equity Funds Used During Construction	5,549	5,949	6,094
Interest Expense	(221,977)	(242,000)	(241,134)
INCOME BEFORE INCOME TAX EXPENSE	678,690	842,922	890,471
Income Tax Expense	213,697	301,306	310,195
NET INCOME	464,993	541,616	580,276
Net Income Attributable to Noncontrolling Interest	-	-	2,042
NET INCOME ATTRIBUTABLE TO OPCo SHAREHOLDERS	464,993	541,616	578,234
Preferred Stock Dividend Requirements Including Capital Stock Expense	1,259	881	889
EARNINGS ATTRIBUTABLE TO OPCo COMMON SHAREHOLDER	$ 463,734	$ 540,735	$ 577,345

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

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 225.

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2011, 2010 and 2009
(in thousands)

	2011	2010	2009
NET INCOME	$ 464,993	$ 541,616	$ 580,276
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES			
Cash Flow Hedges, Net of Tax of $1,477 in 2011, $529 in 2010 and $3,365 in 2009	(2,743)	(981)	6,249
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $5,894 in 2011, $5,128 in 2010 and $4,614 in 2009	10,946	9,522	8,568
Pension and OPEB Funded Status, Net of Tax of $13,876 in 2011, $10,901 in 2010 and $870 in 2009	(25,770)	(20,245)	1,615
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	(17,567)	(11,704)	16,432
TOTAL COMPREHENSIVE INCOME	447,426	529,912	596,708
Total Comprehensive Income Attributable to Noncontrolling Interest	-	-	2,042
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO OPCo SHAREHOLDERS	$ 447,426	$ 529,912	$ 594,666

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 225.

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Years Ended December 31, 2011, 2010 and 2009
(in thousands)

	OPCo Common Shareholder					
	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
TOTAL EQUITY – DECEMBER 31, 2008	$ 321,201	$ 1,158,172	$ 2,372,720	$ (184,883)	$ 16,799	$ 3,684,009
Capital Contribution from Parent		550,000				550,000
Common Stock Dividends – Affiliated			(245,000)			(245,000)
Common Stock Dividends – Nonaffiliated					(2,042)	(2,042)
Preferred Stock Dividends			(732)			(732)
Purchase of JMG		36,509			(17,910)	18,599
Capital Stock Expense		157	(157)			-
Noncash Dividend of Property to Parent			(8,123)			(8,123)
Other Changes in Equity					1,111	1,111
SUBTOTAL – EQUITY						3,997,822
NET INCOME			578,234		2,042	580,276
OTHER COMPREHENSIVE INCOME				16,432		16,432
TOTAL EQUITY – DECEMBER 31, 2009	321,201	1,744,838	2,696,942	(168,451)	-	4,594,530
Common Stock Dividends			(469,075)			(469,075)
Preferred Stock Dividends			(732)			(732)
Gain on Reacquired Preferred Stock		4				4
Capital Stock Expense		149	(149)			-
SUBTOTAL – EQUITY						4,124,727
NET INCOME			541,616			541,616
OTHER COMPREHENSIVE LOSS				(11,704)		(11,704)
TOTAL EQUITY – DECEMBER 31, 2010	321,201	1,744,991	2,768,602	(180,155)	-	4,654,639
Common Stock Dividends			(650,000)			(650,000)
Preferred Stock Dividends			(671)			(671)
Loss on Reacquired Preferred Stock		(1,216)				(1,216)
Capital Stock Expense		324	(324)			-
SUBTOTAL – EQUITY						4,002,752
NET INCOME			464,993			464,993
OTHER COMPREHENSIVE LOSS				(17,567)		(17,567)
TOTAL EQUITY – DECEMBER 31, 2011	$ 321,201	$ 1,744,099	$ 2,582,600	$ (197,722)	$ -	$ 4,450,178

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 225.

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2011 and 2010
(in thousands)

	2011	2010
CURRENT ASSETS		
Cash and Cash Equivalents	$ 2,095	$ 949
Advances to Affiliates	219,458	154,702
Accounts Receivable:		
Customers	146,432	136,373
Affiliated Companies	162,830	252,851
Accrued Unbilled Revenues	19,012	60,749
Miscellaneous	16,994	15,042
Allowance for Uncollectible Accounts	(3,563)	(3,768)
Total Accounts Receivable	341,705	461,247
Fuel	262,886	330,171
Materials and Supplies	201,325	204,700
Risk Management Assets	54,293	54,547
Accrued Tax Benefits	11,975	77,818
Prepayments and Other Current Assets	41,560	77,884
TOTAL CURRENT ASSETS	1,135,297	1,362,018
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	9,502,614	9,576,404
Transmission	1,948,329	1,896,989
Distribution	3,545,574	3,422,413
Other Property, Plant and Equipment	546,642	562,847
Construction Work in Progress	354,465	325,903
Total Property, Plant and Equipment	15,897,624	15,784,556
Accumulated Depreciation and Amortization	5,742,561	5,533,889
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	10,155,063	10,250,667
OTHER NONCURRENT ASSETS		
Regulatory Assets	1,370,504	1,232,122
Long-term Risk Management Assets	53,614	50,101
Deferred Charges and Other Noncurrent Assets	309,775	342,127
TOTAL OTHER NONCURRENT ASSETS	1,733,893	1,624,350
TOTAL ASSETS	$ 13,024,253	$ 13,237,035

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 225.

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
December 31, 2011 and 2010

	2011	2010
	(in thousands)	
CURRENT LIABILITIES		
Accounts Payable:		
General	$ 293,730	$ 269,165
Affiliated Companies	183,898	202,050
Long-term Debt Due Within One Year – Nonaffiliated	244,500	165,000
Risk Management Liabilities	36,561	38,133
Customer Deposits	55,785	57,669
Accrued Taxes	450,570	455,825
Accrued Interest	66,441	67,017
Other Current Liabilities	182,490	210,555
TOTAL CURRENT LIABILITIES	1,513,975	1,465,414
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	3,609,648	3,803,352
Long-term Debt – Affiliated	200,000	200,000
Long-term Risk Management Liabilities	17,890	14,626
Deferred Income Taxes	2,245,380	2,136,467
Regulatory Liabilities and Deferred Investment Tax Credits	301,124	290,291
Employee Benefits and Pension Obligations	335,029	383,160
Deferred Credits and Other Noncurrent Liabilities	351,029	272,470
TOTAL NONCURRENT LIABILITIES	7,060,100	7,100,366
TOTAL LIABILITIES	8,574,075	8,565,780
Cumulative Preferred Stock Not Subject to Mandatory Redemption	-	16,616
Rate Matters (Note 3)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 40,000,000 Shares		
Outstanding – 27,952,473 Shares	321,201	321,201
Paid-in Capital	1,744,099	1,744,991
Retained Earnings	2,582,600	2,768,602
Accumulated Other Comprehensive Income (Loss)	(197,722)	(180,155)
TOTAL COMMON SHAREHOLDER'S EQUITY	4,450,178	4,654,639
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 13,024,253	$ 13,237,035

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 225.

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2011, 2010 and 2009
(in thousands)

	2011	2010	2009
OPERATING ACTIVITIES			
Net Income	$ 464,993	$ 541,616	$ 580,276
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	545,376	513,168	496,470
Deferred Income Taxes	119,184	292,831	514,201
Asset Impairments and Other Related Charges	89,824	-	-
Carrying Costs Income	(53,345)	(31,796)	(18,354)
Allowance for Equity Funds Used During Construction	(5,549)	(5,949)	(6,094)
Mark-to-Market of Risk Management Contracts	(3,695)	25,251	(10,271)
Pension Contributions to Qualified Plan Trust	(127,884)	(58,639)	-
Property Taxes	(5,722)	(19,324)	(14,474)
Fuel Over/Under-Recovery, Net	(727)	(131,850)	(333,598)
Change in Other Noncurrent Assets	(73,242)	3,797	(31,547)
Change in Other Noncurrent Liabilities	85,173	(17,079)	50,986
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	116,197	(126,071)	32,482
Fuel, Materials and Supplies	79,787	66,700	(198,124)
Accounts Payable	(17,059)	72,694	(189,103)
Accrued Taxes, Net	36,466	131,441	(136,746)
Other Current Assets	7,789	924	16,955
Other Current Liabilities	(15,821)	53,985	(34,048)
Net Cash Flows from Operating Activities	1,241,745	1,311,699	719,011
INVESTING ACTIVITIES			
Construction Expenditures	(454,873)	(504,702)	(716,543)
Change in Advances to Affiliates, Net	(64,756)	283,650	(438,352)
Acquisitions of Assets	(2,229)	(5,801)	(1,429)
Proceeds from Sales of Assets	47,463	14,382	35,706
Other Investing Activities	29,014	26,400	21,680
Net Cash Flows Used for Investing Activities	(445,381)	(186,071)	(1,098,938)
FINANCING ACTIVITIES			
Capital Contribution from Parent	-	-	550,000
Issuance of Long-term Debt – Nonaffiliated	49,748	351,824	584,936
Change in Advances from Affiliates, Net	-	(24,202)	(184,550)
Retirement of Long-term Debt – Nonaffiliated	(165,000)	(868,580)	(295,500)
Retirement of Long-term Debt – Affiliated	-	(100,000)	-
Retirement of Cumulative Preferred Stock	(17,831)	(7)	(1)
Principal Payments for Capital Lease Obligations	(11,854)	(11,617)	(6,976)
Dividends Paid on Common Stock – Nonaffiliated	-	-	(2,042)
Dividends Paid on Common Stock – Affiliated	(650,000)	(469,075)	(245,000)
Dividends Paid on Cumulative Preferred Stock	(671)	(732)	(732)
Acquisition of JMG Noncontrolling Interest	-	-	(28,221)
Other Financing Activities	390	(5,370)	(2,649)
Net Cash Flows from (Used for) Financing Activities	(795,218)	(1,127,759)	369,265
Net Increase (Decrease) in Cash and Cash Equivalents	1,146	(2,131)	(10,662)
Cash and Cash Equivalents at Beginning of Period	949	3,080	13,742
Cash and Cash Equivalents at End of Period	$ 2,095	$ 949	$ 3,080
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 226,711	$ 239,984	$ 241,627
Net Cash Paid (Received) for Income Taxes	81,740	(78,268)	(15,759)
Noncash Acquisitions Under Capital Leases	5,766	33,369	3,275
Government Grants Included in Accounts Receivable at December 31,	1,383	9,260	-
Construction Expenditures Included in Current Liabilities at December 31,	61,428	31,939	61,035
Noncash Dividend of Property to Parent	-	-	8,123

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 225.

OHIO POWER COMPANY CONSOLIDATED
INDEX OF NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to OPCo's financial statements are combined with the notes to financial statements for other registrant subsidiaries. Listed below are the notes that apply to OPCo. The footnotes begin on page 225.

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

EXECUTIVE OVERVIEW

Company Overview

As a public utility, PSO engages in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to approximately 532,000 retail customers in its service territory in eastern and southwestern Oklahoma. PSO sells electric power at wholesale to other utilities, municipalities and electric cooperatives.

PSO, as a member of the CSW Operating Agreement, is compensated for energy delivered to the other member based upon the delivering member's incremental cost plus a portion of the savings realized by the purchasing member that avoids the use of more costly alternatives. PSO and SWEPCo share the revenues and costs of sales to neighboring utilities and power marketers made by AEPSC on their behalf based upon the relative magnitude of the energy each company provides to make such sales. PSO shares off-system sales margins, if positive on an annual basis, with its customers.

Under the SIA, AEPSC allocates physical and financial revenues and expenses from transactions with neighboring utilities, power marketers and other power and gas risk management activities based upon the location of such activity, with margins resulting from trading and marketing activities originating in PJM and MISO generally accruing to the benefit of the AEP East companies and trading and marketing activities originating in SPP generally accruing to the benefit of PSO and SWEPCo. Margins resulting from other transactions are allocated among the AEP East companies, PSO and SWEPCo in proportion to the marketing realization directly assigned to each zone for the current month plus the preceding eleven months.

AEPSC conducts power, gas, coal and emission allowance risk management activities on PSO's behalf. PSO shares in the revenues and expenses associated with these risk management activities, as described in the preceding paragraph, with the AEP East companies and SWEPCo. Power and gas risk management activities are allocated based on the CSW Operating Agreement and the SIA. PSO shares in coal and emission allowance risk management activities based on its proportion of fossil fuels burned by the AEP System. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas, coal and emission allowances. The electricity, gas, coal and emission allowance contracts include physical transactions, OTC options and financially-settled swaps and exchange-traded futures and options. AEPSC settles the majority of the physical forward contracts by entering into offsetting contracts.

PSO is jointly and severally liable for activity conducted by AEPSC on behalf of PSO and SWEPCo related to purchase power and sale activity pursuant to the SIA.

Litigation and Environmental Issues

In the ordinary course of business, PSO is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot state what the eventual resolution will be or the timing and amount of any loss, fine or penalty may be. Management assesses the probability of loss for each contingency and accrues a liability for cases which have a probable likelihood of loss if the loss can be estimated. For details on regulatory proceedings and pending litigation, see Note 3 – Rate Matters and Note 5 – Commitments, Guarantees and Contingencies. Adverse results in these proceedings have the potential to materially affect net income, financial condition and cash flows.

See the "Executive Overview" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" section beginning on page 375 for additional discussion of relevant factors.

RESULTS OF OPERATIONS

KWH Sales/Degree Days

Summary of KWH Energy Sales

	Years Ended December 31, 2011	2010	2009
	(in millions of KWHs)		
Retail:			
Residential	6,741	6,595	6,004
Commercial	5,190	5,136	4,974
Industrial	4,956	4,921	4,742
Miscellaneous	1,310	1,265	1,236
Total Retail	18,197	17,917	16,956
Wholesale	1,113	1,190	982
Total KWHs	19,310	19,107	17,938

Cooling degree days and heating degree days are metrics commonly used in the utility industry as a measure of the impact of weather on net income.

Summary of Heating and Cooling Degree Days

	Years Ended December 31, 2011	2010	2009
	(in degree days)		
Actual - Heating (a)	1,879	1,993	1,840
Normal - Heating (b)	1,796	1,784	1,789
Actual - Cooling (c)	2,788	2,380	1,861
Normal - Cooling (b)	2,102	2,095	2,126

(a) Western Region heating degree days are calculated on a 55 degree temperature base.
(b) Normal Heating/Cooling represents the thirty-year average of degree days.
(c) Western Region cooling degree days are calculated on a 65 degree temperature base.

2011 Compared to 2010

Reconciliation of Year Ended December 31, 2010 to Year Ended December 31, 2011
Net Income
(in millions)

Year Ended December 31, 2010	$	73
Changes in Gross Margin:		
Retail Margins (a)		15
Transmission Revenues		2
Total Change in Gross Margin		17
Changes in Expenses and Other:		
Other Operation and Maintenance		32
Depreciation and Amortization		9
Taxes Other Than Income Taxes		1
Other Income		2
Interest Expense		9
Total Change in Expenses and Other		53
Income Tax Expense		(18)
Year Ended December 31, 2011	$	125

(a) Includes firm wholesale sales to municipals and cooperatives.

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

- **Retail Margins** increased $15 million primarily due to the following:
  - A $14 million increase in weather-related usage primarily due to a 17% increase in cooling degree days.
  - A $6 million increase primarily due to decreased capacity and fuel costs.

  These increases were partially offset by:
  - A $7 million decrease primarily due to revenue decreases from rate riders. This decrease in retail margins had corresponding decreases to riders/trackers recognized in other expense items.

Expenses and Other and Income Tax Expense changed between years as follows:

- **Other Operation and Maintenance** expenses decreased $32 million primarily due to the following:
  - A $24 million decrease due to expenses related to cost reduction initiatives recorded in 2010.
  - A $9 million decrease in plant maintenance expenses resulting primarily from a decrease in planned generation plant maintenance in 2011 and from the 2011 deferral of generation maintenance expenses as a result of PSO's base rate case.
  - A $4 million decrease in operation expenses due to lower employee-related expenses.

  These decreases were partially offset by:
  - A $7 million increase in demand side management programs.
- **Depreciation and Amortization** expenses decreased $9 million primarily due to a decrease in amortization of regulatory assets related to the Lawton Settlement which was fully recovered in August 2010.
- **Interest Expense** decreased $9 million primarily due to lower long-term interest rates, lower long-term debt outstanding in 2011 and a reduction in tax-related interest.
- **Income Tax Expense** increased $18 million primarily due to an increase in pretax book income and the recording of state income tax adjustments resulting from the filing of prior year tax returns.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES, NEW ACCOUNTING PRONOUNCEMENTS

See the "Critical Accounting Policies and Estimates" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" beginning on page 375 for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets and pension and other postretirement benefits.

See the "New Accounting Pronouncements" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" beginning on page 375 for a discussion of the adoption and impact of new accounting pronouncements.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying balance sheets of Public Service Company of Oklahoma (the "Company") as of December 31, 2011 and 2010, and the related statements of income, comprehensive income (loss), changes in common shareholder's equity, and cash flows for each of the three years in the period ended December 31, 2011. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of Public Service Company of Oklahoma as of December 31, 2011 and 2010, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the financial statements, in 2011 the Company changed its method of presenting comprehensive income due to the adoption of FASB Accounting Standards Update No. 2011-05, *Comprehensive Income (Topic 220): Presentation of Comprehensive Income*. The change in presentation has been applied retrospectively to all periods presented.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 28, 2012

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Public Service Company of Oklahoma (PSO) is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. PSO's internal control system was designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of PSO's internal control over financial reporting as of December 31, 2011. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework. Based on management's assessment, PSO's internal control over financial reporting was effective as of December 31, 2011.

This annual report does not include an attestation report of PSO's registered public accounting firm regarding internal control over financial reporting pursuant to the Securities and Exchange Commission rules that permit PSO to provide only management's report in this annual report.

**PUBLIC SERVICE COMPANY OF OKLAHOMA
STATEMENTS OF INCOME
For the Years Ended December 31, 2011, 2010 and 2009
(in thousands)**

	2011	2010	2009
REVENUES			
Electric Generation, Transmission and Distribution	$ 1,345,551	$ 1,246,916	$ 1,075,014
Sales to AEP Affiliates	14,192	23,528	45,756
Other Revenues	3,645	3,218	3,980
TOTAL REVENUES	1,363,388	1,273,662	1,124,750
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	465,546	373,317	310,168
Purchased Electricity for Resale	163,550	187,106	180,055
Purchased Electricity from AEP Affiliates	50,092	46,013	19,331
Other Operation	201,247	222,396	185,575
Maintenance	104,732	115,788	108,020
Depreciation and Amortization	95,915	104,929	110,149
Taxes Other Than Income Taxes	41,295	42,121	41,144
TOTAL EXPENSES	1,122,377	1,091,670	954,442
OPERATING INCOME	241,011	181,992	170,308
Other Income (Expense):			
Interest Income	596	308	1,879
Carrying Costs Income	4,033	3,145	4,642
Allowance for Equity Funds Used During Construction	1,317	804	1,787
Interest Expense	(54,700)	(63,362)	(59,093)
INCOME BEFORE INCOME TAX EXPENSE	192,257	122,887	119,523
Income Tax Expense	67,629	50,100	43,921
NET INCOME	124,628	72,787	75,602
Preferred Stock Dividend Requirements Including Capital Stock Expense	434	200	212
EARNINGS ATTRIBUTABLE TO COMMON STOCK	$ 124,194	$ 72,587	$ 75,390

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

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 225.

PUBLIC SERVICE COMPANY OF OKLAHOMA
STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2011, 2010 and 2009
(in thousands)

	2011	2010	2009
NET INCOME	$ 124,628	$ 72,787	$ 75,602
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES			
Cash Flow Hedges, Net of Tax of $724 in 2011, $4,896 in 2010 and $57 in 2009	(1,345)	9,093	105
TOTAL COMPREHENSIVE INCOME	$ 123,283	$ 81,880	$ 75,707

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 225.

PUBLIC SERVICE COMPANY OF OKLAHOMA
STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Years Ended December 31, 2011, 2010 and 2009
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2008	$ 157,230	$ 340,016	$ 251,704	$ (704)	$ 748,246
Capital Contribution from Parent		20,000			20,000
Common Stock Dividends			(32,000)		(32,000)
Preferred Stock Dividends			(212)		(212)
Gain on Reacquired Preferred Stock		1			1
Other Changes in Common Shareholder's Equity		4,214	(4,214)		-
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					736,035
NET INCOME			75,602		75,602
OTHER COMPREHENSIVE INCOME				105	105
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2009	157,230	364,231	290,880	(599)	811,742
Common Stock Dividends			(51,026)		(51,026)
Preferred Stock Dividends			(200)		(200)
Gain on Reacquired Preferred Stock		76			76
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					760,592
NET INCOME			72,787		72,787
OTHER COMPREHENSIVE INCOME				9,093	9,093
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2010	157,230	364,307	312,441	8,494	842,472
Common Stock Dividends			(72,500)		(72,500)
Preferred Stock Dividends			(180)		(180)
Loss on Reacquired Preferred Stock		(270)			(270)
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					769,522
NET INCOME			124,628		124,628
OTHER COMPREHENSIVE LOSS				(1,345)	(1,345)
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2011	$ 157,230	$ 364,037	$ 364,389	$ 7,149	$ 892,805

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 225.

PUBLIC SERVICE COMPANY OF OKLAHOMA
BALANCE SHEETS
ASSETS
December 31, 2011 and 2010
(in thousands)

	2011	2010
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,413	$ 470
Advances to Affiliates	39,876	-
Accounts Receivable:		
Customers	39,977	43,049
Affiliated Companies	23,079	65,070
Miscellaneous	8,993	5,497
Allowance for Uncollectible Accounts	(777)	(971)
Total Accounts Receivable	71,272	112,645
Fuel	20,854	20,176
Materials and Supplies	50,347	46,247
Risk Management Assets	565	14,225
Accrued Tax Benefits	6,733	38,589
Regulatory Asset for Under-Recovered Fuel Costs	4,313	37,262
Prepayments and Other Current Assets	13,453	9,416
TOTAL CURRENT ASSETS	208,826	279,030
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	1,317,948	1,330,368
Transmission	692,644	663,994
Distribution	1,762,110	1,686,470
Other Property, Plant and Equipment	214,626	235,406
Construction Work in Progress	70,371	59,091
Total Property, Plant and Equipment	4,057,699	3,975,329
Accumulated Depreciation and Amortization	1,266,816	1,255,064
TOTAL PROPERTY, PLANT AND EQUIPMENT -- NET	2,790,883	2,720,265
OTHER NONCURRENT ASSETS		
Regulatory Assets	266,545	263,545
Long-term Risk Management Assets	314	252
Deferred Charges and Other Noncurrent Assets	13,536	20,979
TOTAL OTHER NONCURRENT ASSETS	280,395	284,776
TOTAL ASSETS	$ 3,280,104	$ 3,284,071

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 225.

PUBLIC SERVICE COMPANY OF OKLAHOMA
BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
December 31, 2011 and 2010

	2011	2010
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ -	$ 91,382
Accounts Payable:		
General	76,607	69,155
Affiliated Companies	45,029	53,179
Long-term Debt Due Within One Year – Nonaffiliated	311	25,000
Risk Management Liabilities	1,280	922
Customer Deposits	47,493	41,217
Accrued Taxes	21,660	25,390
Accrued Interest	12,637	9,238
Other Current Liabilities	43,586	38,095
TOTAL CURRENT LIABILITIES	248,603	353,578
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	947,053	946,186
Long-term Risk Management Liabilities	1,330	197
Deferred Income Taxes	726,463	660,783
Regulatory Liabilities and Deferred Investment Tax Credits	334,812	336,961
Employee Benefits and Pension Obligations	84,548	98,107
Deferred Credits and Other Noncurrent Liabilities	44,490	40,905
TOTAL NONCURRENT LIABILITIES	2,138,696	2,083,139
TOTAL LIABILITIES	2,387,299	2,436,717
Cumulative Preferred Stock Not Subject to Mandatory Redemption	-	4,882
Rate Matters (Note 3)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $15 Per Share:		
Authorized – 11,000,000 Shares		
Issued – 10,482,000 Shares		
Outstanding – 9,013,000 Shares	157,230	157,230
Paid-in Capital	364,037	364,307
Retained Earnings	364,389	312,441
Accumulated Other Comprehensive Income (Loss)	7,149	8,494
TOTAL COMMON SHAREHOLDER'S EQUITY	892,805	842,472
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 3,280,104	$ 3,284,071

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 225.

PUBLIC SERVICE COMPANY OF OKLAHOMA
STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2011, 2010 and 2009
(in thousands)

	2011	2010	2009
OPERATING ACTIVITIES			
Net Income	$ 124,628	$ 72,787	$ 75,602
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	95,915	104,929	110,149
Deferred Income Taxes	61,581	92,695	56,029
Carrying Costs Income	(4,033)	(3,145)	(4,642)
Allowance for Equity Funds Used During Construction	(1,317)	(804)	(1,787)
Mark-to-Market of Risk Management Contracts	1,290	160	1,791
Pension Contributions to Qualified Plan Trust	(33,189)	(12,848)	-
Fuel Over/Under-Recovery, Net	32,949	(88,349)	(59,462)
Unrealized Forward Commitments, Net	(1,402)	46	(1,928)
Change in Other Noncurrent Assets	16,304	(19,325)	7,713
Change in Other Noncurrent Liabilities	32,177	16,612	625
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	44,414	(10,094)	81,446
Fuel, Materials and Supplies	(4,778)	(617)	5,301
Accounts Payable	(20,068)	(20,601)	(16,431)
Accrued Taxes, Net	19,535	(23,605)	(10,230)
Other Current Assets	4,855	4,446	(5,927)
Other Current Liabilities	10,628	(18,341)	1,404
Net Cash Flows from Operating Activities	379,489	93,946	239,653
INVESTING ACTIVITIES			
Construction Expenditures	(140,327)	(194,896)	(175,122)
Change in Advances to Affiliates, Net	(39,876)	62,695	(62,695)
Other Investing Activities	1,126	(368)	(158)
Net Cash Flows Used for Investing Activities	(179,077)	(132,569)	(237,975)
FINANCING ACTIVITIES			
Capital Contribution from Parent	-	-	20,000
Issuance of Long-term Debt – Nonaffiliated	248,909	2,240	280,732
Change in Advances from Affiliates, Net	(91,382)	91,382	(70,308)
Retirement of Long-term Debt – Nonaffiliated	(275,000)	-	(200,000)
Retirement of Cumulative Preferred Stock	(5,152)	(300)	(2)
Principal Payments for Capital Lease Obligations	(4,189)	(3,991)	(1,485)
Dividends Paid on Common Stock	(72,500)	(51,026)	(32,000)
Dividends Paid on Cumulative Preferred Stock	(180)	(200)	(212)
Other Financing Activities	25	192	1,048
Net Cash Flows from (Used For) Financing Activities	(199,469)	38,297	(2,227)
Net Increase (Decrease) in Cash and Cash Equivalents	943	(326)	(549)
Cash and Cash Equivalents at Beginning of Period	470	796	1,345
Cash and Cash Equivalents at End of Period	$ 1,413	$ 470	$ 796
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 37,573	$ 57,970	$ 71,135
Net Cash Paid (Received) for Income Taxes	(16,043)	(16,770)	1,040
Noncash Acquisitions Under Capital Leases	1,078	13,794	3,478
Construction Expenditures Included in Current Liabilities at December 31,	28,427	6,842	11,901

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 225.

PUBLIC SERVICE COMPANY OF OKLAHOMA
INDEX OF NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to PSO's financial statements are combined with the notes to financial statements for other registrant subsidiaries. Listed below are the notes that apply to PSO. The footnotes begin on page 225.

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

EXECUTIVE OVERVIEW

Company Overview

As a public utility, SWEPCo engages in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to approximately 521,000 retail customers in its service territory in northeastern and panhandle of Texas, northwestern Louisiana and western Arkansas. SWEPCo consolidates its wholly-owned subsidiary, Southwest Arkansas Utilities Corporation. SWEPCo also consolidates Sabine Mining Company, a variable interest entity. SWEPCo sells electric power at wholesale to other utilities, municipalities and electric cooperatives.

SWEPCo, as a member of the CSW Operating Agreement, is compensated for energy delivered to the other member based upon the delivering member's incremental cost plus a portion of the savings realized by the purchasing member that avoids the use of more costly alternatives. PSO and SWEPCo share the revenues and costs for sales to neighboring utilities and power marketers made by AEPSC on their behalf based upon the relative magnitude of the energy each company provides to make such sales. SWEPCo shares these margins with its customers.

Under the SIA, AEPSC allocates physical and financial revenues and expenses from transactions with neighboring utilities, power marketers and other power and gas risk management activities based upon the location of such activity, with margins resulting from trading and marketing activities originating in PJM and MISO generally accruing to the benefit of the AEP East companies and trading and marketing activities originating in SPP generally accruing to the benefit of PSO and SWEPCo. Margins resulting from other transactions are allocated among the AEP East companies, PSO and SWEPCo in proportion to the marketing realization directly assigned to each zone for the current month plus the preceding eleven months.

AEPSC conducts power, gas, coal and emission allowance risk management activities on SWEPCo's behalf. SWEPCo shares in the revenues and expenses associated with these risk management activities, as described in the preceding paragraph, with the AEP East companies and PSO. Power and gas risk management activities are allocated based on the CSW Operating Agreement and the SIA. SWEPCo shares in coal and emission allowance risk management activities based on its proportion of fossil fuels burned by the AEP System. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas, coal and emission allowances. The electricity, gas, coal and emission allowance contracts include physical transactions, OTC options and financially-settled swaps and exchange-traded futures and options. AEPSC settles the majority of the physical forward contracts by entering into offsetting contracts.

SWEPCo is jointly and severally liable for activity conducted by AEPSC on the behalf of PSO and SWEPCo related to purchase power and sale activity pursuant to the SIA.

Regulatory Activity

Turk Plant

SWEPCo is currently constructing the Turk Plant, a new base load 600 MW coal generating unit in Arkansas, which is expected to be in service in the fourth quarter of 2012. SWEPCo owns 73% (440 MW) of the Turk Plant and will operate the completed facility. SWEPCo's share of construction costs is currently estimated to be $1.3 billion, excluding AFUDC, plus an additional $122 million for transmission, excluding AFUDC. SWEPCo submitted applications with the APSC, the LPSC and the PUCT for approval to build the Turk Plant. The APSC and the LPSC approved SWEPCo's applications. However, in June 2010, the APSC issued an order which reversed and set aside the previously granted Certificate of Environmental Compatibility and Public Need (CECPN). The PUCT approved SWEPCo's application with several conditions, including a Texas jurisdictional capital costs cap. In November 2011, the Texas Court of Appeals affirmed the PUCT's order in all respects. As a result, in the fourth quarter of 2011, SWEPCo recorded a pretax write-off of $49 million in Asset Impairments and Other Related Charges on the statement of income related to the estimated excess of the Texas jurisdictional portion of the Turk

Plant above the Texas jurisdictional capital costs cap. In December 2011, SWEPCo and the Texas Industrial Energy Consumers filed motions for rehearing at the Texas Court of Appeals which were denied in January 2012. SWEPCo intends to seek review of the Texas Court of Appeals decision at the Supreme Court of Texas.

Several parties, including the Hempstead County Hunting Club, the Sierra Club and the National Audubon Society had challenged the air permit, the wastewater discharge permit and the wetlands permit that were issued for the Turk Plant. In 2011, SWEPCo entered into settlement agreements with these parties which resolved all outstanding issues related to the permits and the APSC's grant of a CECPN. The parties dismissed all pending permit and CECPN challenges at the APSC, other administrative agencies and the courts. See "Turk Plant" section of Note 3.

Litigation and Environmental Issues

In the ordinary course of business, SWEPCo is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot state what the eventual resolution will be or the timing and amount of any loss, fine or penalty may be. Management assesses the probability of loss for each contingency and accrues a liability for cases which have a probable likelihood of loss if the loss can be estimated. For details on regulatory proceedings and pending litigation, see Note 3 – Rate Matters and Note 5 – Commitments, Guarantees and Contingencies. Adverse results in these proceedings have the potential to materially affect net income, financial condition and cash flows.

See the "Executive Overview" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" section beginning on page 375 for additional discussion of relevant factors.

RESULTS OF OPERATIONS

KWH Sales/Degree Days

Summary of KWH Energy Sales

	Years Ended December 31,		
	2011	**2010**	**2009**
	(in millions of KWHs)		
Retail:			
Residential	6,908	6,361	5,587
Commercial	6,280	6,117	5,957
Industrial	5,408	5,254	4,460
Miscellaneous	82	81	82
Total Retail	18,678	17,813	16,086
Wholesale	7,947	7,333	6,527
Total KWHs	26,625	25,146	22,613

Cooling degree days and heating degree days are metrics commonly used in the utility industry as a measure of the impact of weather on net income.

Summary of Heating and Cooling Degree Days

	Years Ended December 31,		
	2011	2010	2009
		(in degree days)	
Actual - Heating (a)	1,271	1,543	1,270
Normal - Heating (b)	1,260	1,253	1,263
Actual - Cooling (c)	2,874	2,592	1,956
Normal - Cooling (b)	2,231	2,213	2,231

(a) Western Region heating degree days are calculated on a 55 degree temperature base.
(b) Normal Heating/Cooling represents the thirty-year average of degree days.
(c) Western Region cooling degree days are calculated on a 65 degree temperature base.

2011 Compared to 2010

Reconciliation of Year Ended December 31, 2010 to Year Ended December 31, 2011
Net Income
(in millions)

Year Ended December 31, 2010	$	147
Changes in Gross Margin:		
Retail Margins (a)		71
Off-system Sales		(1)
Transmission Revenues		2
Other Revenues		3
Total Change in Gross Margin		75
Changes in Expenses and Other:		
Other Operation and Maintenance		(16)
Asset Impairment and Other Related Charges		(49)
Depreciation and Amortization		(6)
Taxes Other Than Income Taxes		(2)
Interest Income		1
Allowance for Equity Funds Used During Construction		3
Interest Expense		5
Total Change in Expenses and Other		(64)
Income Tax Expense		7
Year Ended December 31, 2011	$	165

(a) Includes firm wholesale sales to municipals and cooperatives.

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

- **Retail Margins** increased $71 million primarily due to:
  - A $30 million increase in revenues primarily due to Stall Unit recovery riders in Arkansas and Louisiana, rate increases from wholesale customers on formula rates and base rate increases in Texas.
  - A $30 million increase due to increased gross margin from sales to customers previously served by Valley Electric Membership Corporation (VEMCO). SWEPCo acquired VEMCO assets and began serving VEMCO customers in October 2010.
  - A $5 million increase in weather-related usage primarily due to a 13% increase in cooling degree days, partially offset by an 18% decrease in heating degree days.

Expenses and Other and Income Tax Expense changed between years as follows:

- **Other Operation and Maintenance** expenses increased $16 million primarily due to:
  - A $38 million increase in maintenance expenses primarily due to planned and unplanned generation plant outages and increased distribution expenses resulting from vegetation management and storm-related expenses.
  - A $4 million increase in customer-related expenses primarily due to higher demand side management activities in addition to increased customer record and collection expenses.

  These increases were partially offset by:
  - A $30 million decrease due to expenses related to the cost reduction initiatives recorded in 2010.
- **Asset Impairment and Other Related Charges** included a fourth quarter 2011 write-off of $49 million related to the Texas jurisdictional portion of the Turk Plant as a result of the November 2011 Texas Court of Appeals decision upholding the Texas capital cost cap.
- **Depreciation and Amortization** expenses increased $6 million primarily due to a greater depreciation base, including the addition of the Stall Unit which was placed into service in June 2010.
- **Allowance for Equity Funds Used During Construction** increased $3 million primarily due to construction at the Turk Plant, partially offset by completed construction of the Stall Unit in June 2010.
- **Interest Expense** decreased $5 million primarily due to an increase in the debt component of AFUDC due to the new Turk Plant generation project, partially offset by a decrease in the debt component of AFUDC due to completed construction of the Stall Unit in June 2010 and an increase in interest related to the issuance of senior unsecured notes in the first quarter of 2010.
- **Income Tax Expense** decreased $7 million primarily due to the recording of federal and state income tax adjustments resulting from the filing of prior year tax returns and other book/tax differences which are accounted for on a flow-through basis, partially offset by an increase in pretax book income.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES, NEW ACCOUNTING PRONOUNCEMENTS

See the "Critical Accounting Policies and Estimates" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" beginning on page 375 for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets and pension and other postretirement benefits.

See the "New Accounting Pronouncements" section of "Combined Management's Narrative Discussion and Analysis of Registrant Subsidiaries" beginning on page 375 for a discussion of the adoption and impact of new accounting pronouncements.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of Southwestern Electric Power Company Consolidated (the "Company") as of December 31, 2011 and 2010, and the related consolidated statements of income, comprehensive income (loss), changes in equity, and cash flows for each of the three years in the period ended December 31, 2011. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Southwestern Electric Power Company Consolidated as of December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, in 2011 the Company changed its method of presenting comprehensive income due to the adoption of FASB Accounting Standards Update No. 2011-05, *Comprehensive Income (Topic 220): Presentation of Comprehensive Income.* The change in presentation has been applied retrospectively to all periods presented. As discussed in Note 2 to the consolidated financial statements, the Company adopted FASB Accounting Standards Update No. 2009-17, *Consolidations (Topic 810): Improvements to Financial Reporting by Enterprises Involved with Variable Interest Entities*, effective January 1, 2010.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 28, 2012

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Southwestern Electric Power Company Consolidated (SWEPCo) is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. SWEPCo's internal control system was designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of SWEPCo's internal control over financial reporting as of December 31, 2011. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework. Based on management's assessment, SWEPCo's internal control over financial reporting was effective as of December 31, 2011.

This annual report does not include an attestation report of SWEPCo's registered public accounting firm regarding internal control over financial reporting pursuant to the Securities and Exchange Commission rules that permit SWEPCo to provide only management's report in this annual report.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2011, 2010 and 2009
(in thousands)

	2011	2010	2009
REVENUES			
Electric Generation, Transmission and Distribution	$ 1,594,192	$ 1,469,514	$ 1,315,056
Sales to AEP Affiliates	57,615	51,870	29,318
Lignite Revenues – Nonaffiliated	-	-	43,239
Other Revenues	2,019	2,150	1,689
TOTAL REVENUES	1,653,826	1,523,534	1,389,302
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	626,599	587,058	495,928
Purchased Electricity for Resale	152,645	125,064	127,170
Purchased Electricity from AEP Affiliates	11,808	23,707	42,712
Other Operation	224,068	245,504	249,792
Maintenance	140,981	103,352	105,602
Asset Impairment and Other Related Charges	49,000	-	-
Depreciation and Amortization	133,229	126,901	145,144
Taxes Other Than Income Taxes	65,239	63,151	60,442
TOTAL EXPENSES	1,403,569	1,274,737	1,226,790
OPERATING INCOME	250,257	248,797	162,512
Other Income (Expense):			
Interest Income	2,076	579	1,286
Allowance for Equity Funds Used During Construction	48,731	45,646	46,737
Interest Expense	(81,781)	(86,538)	(70,500)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS	219,283	208,484	140,035
Income Tax Expense	56,903	64,214	17,511
Equity Earnings of Unconsolidated Subsidiary	2,746	2,414	4
INCOME BEFORE EXTRAORDINARY ITEM	165,126	146,684	122,528
EXTRAORDINARY ITEM, NET OF TAX	-	-	(5,325)
NET INCOME	165,126	146,684	117,203
Net Income Attributable to Noncontrolling Interest	3,841	4,093	3,130
NET INCOME ATTRIBUTABLE TO SWEPCo SHAREHOLDERS	161,285	142,591	114,073
Preferred Stock Dividend Requirements Including Capital Stock Expense	579	229	229
EARNINGS ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$ 160,706	$ 142,362	$ 113,844

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

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 225.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2011, 2010 and 2009
(in thousands)

	2011	2010	2009
NET INCOME	$ 165,126	$ 146,684	$ 117,203
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES			
Cash Flow Hedges, Net of Tax of $6,103 in 2011, $401 in 2010 and $533 in 2009	(11,334)	745	989
Reapplication of Regulated Operations Accounting Guidance for Pensions, Net of Tax of $8,223 in 2009	-	-	15,271
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $275 in 2011, $505 in 2010 and $928 in 2009	511	937	1,724
Pension and OPEB Funded Status, Net of Tax of $1,885 in 2011, $636 in 2010 and $617 in 2009	(3,501)	(1,182)	1,145
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	(14,324)	500	19,129
TOTAL COMPREHENSIVE INCOME	150,802	147,184	136,332
Total Comprehensive Income Attributable to Noncontrolling Interest	3,841	4,093	3,130
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO SWEPCo SHAREHOLDERS	$ 146,961	$ 143,091	$ 133,202

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 225.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Years Ended December 31, 2011, 2010 and 2009
(in thousands)

	SWEPCo Common Shareholder					
	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
TOTAL EQUITY – DECEMBER 31, 2008	$ 135,660	$ 530,003	$ 615,110	$ (32,120)	$ 276	$ 1,248,929
Capital Contribution from Parent		142,500				142,500
Common Stock Dividends – Nonaffiliated					(3,375)	(3,375)
Preferred Stock Dividends			(229)			(229)
Other Changes in Equity		2,476	(2,476)			-
SUBTOTAL – EQUITY						1,387,825
NET INCOME			114,073		3,130	117,203
OTHER COMPREHENSIVE INCOME				19,129		19,129
TOTAL EQUITY – DECEMBER 31, 2009	135,660	674,979	726,478	(12,991)	31	1,524,157
Common Stock Dividends – Nonaffiliated					(3,763)	(3,763)
Preferred Stock Dividends			(229)			(229)
SUBTOTAL – EQUITY						1,520,165
NET INCOME			142,591		4,093	146,684
OTHER COMPREHENSIVE INCOME				500		500
TOTAL EQUITY – DECEMBER 31, 2010	135,660	674,979	868,840	(12,491)	361	1,667,349
Common Stock Dividends – Nonaffiliated					(3,811)	(3,811)
Preferred Stock Dividends			(210)			(210)
Loss on Reacquired Preferred Stock		(373)				(373)
SUBTOTAL – EQUITY						1,662,955
NET INCOME			161,285		3,841	165,126
OTHER COMPREHENSIVE LOSS				(14,324)		(14,324)
TOTAL EQUITY – DECEMBER 31, 2011	$ 135,660	$ 674,606	$ 1,029,915	$ (26,815)	$ 391	$ 1,813,757

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 225.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2011 and 2010
(in thousands)

	2011	2010
CURRENT ASSETS		
Cash and Cash Equivalents	$ 801	$ 1,514
Advances to Affiliates	-	86,222
Accounts Receivable:		
Customers	35,054	34,434
Affiliated Companies	23,730	43,219
Miscellaneous	19,370	17,739
Allowance for Uncollectible Accounts	(989)	(588)
Total Accounts Receivable	77,165	94,804
Fuel		
(December 31, 2011 and 2010 amounts include $32,651 and $35,055, respectively, related to Sabine)	102,015	91,777
Materials and Supplies	55,325	50,395
Risk Management Assets	445	1,209
Deferred Income Tax Benefits	8,195	15,529
Accrued Tax Benefits	1,541	37,900
Regulatory Asset for Under-Recovered Fuel Costs	10,843	758
Prepayments and Other Current Assets	16,827	24,270
TOTAL CURRENT ASSETS	273,157	404,378
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	2,326,102	2,297,463
Transmission	988,534	943,724
Distribution	1,675,764	1,611,129
Other Property, Plant and Equipment		
(December 31, 2011 and 2010 amounts include $232,948 and $224,857, respectively, related to Sabine)	637,019	632,158
Construction Work in Progress	1,443,569	1,071,603
Total Property, Plant and Equipment	7,070,988	6,556,077
Accumulated Depreciation and Amortization		
(December 31, 2011 and 2010 amounts include $103,586 and $91,840, respectively, related to Sabine)	2,211,912	2,130,351
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	4,859,076	4,425,726
OTHER NONCURRENT ASSETS		
Regulatory Assets	394,276	332,698
Long-term Risk Management Assets	282	438
Deferred Charges and Other Noncurrent Assets	74,992	80,327
TOTAL OTHER NONCURRENT ASSETS	469,550	413,463
TOTAL ASSETS	$ 5,601,783	$ 5,243,567

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 225.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
December 31, 2011 and 2010

	2011	2010
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 132,473	$ -
Accounts Payable:		
General	181,268	162,271
Affiliated Companies	59,201	64,474
Short-term Debt – Nonaffiliated	17,016	6,217
Long-term Debt Due Within One Year – Nonaffiliated	20,000	41,135
Risk Management Liabilities	24,359	4,067
Customer Deposits	52,095	48,245
Accrued Taxes	44,404	30,516
Accrued Interest	39,629	39,856
Obligations Under Capital Leases	15,058	13,265
Regulatory Liability for Over-Recovered Fuel Costs	5,032	16,432
Provision for Refund	4,404	7,698
Other Current Liabilities	60,009	59,420
TOTAL CURRENT LIABILITIES	654,948	493,596
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,708,637	1,728,385
Long-term Risk Management Liabilities	221	338
Deferred Income Taxes	665,668	624,333
Regulatory Liabilities and Deferred Investment Tax Credits	428,571	393,673
Asset Retirement Obligations	65,673	56,632
Employee Benefits and Pension Obligations	87,159	96,314
Obligations Under Capital Leases	112,802	115,399
Deferred Credits and Other Noncurrent Liabilities	64,347	62,852
TOTAL NONCURRENT LIABILITIES	3,133,078	3,077,926
TOTAL LIABILITIES	3,788,026	3,571,522
Cumulative Preferred Stock Not Subject to Mandatory Redemption	-	4,696
Rate Matters (Note 3)		
Commitments and Contingencies (Note 5)		
EQUITY		
Common Stock – Par Value – $18 Per Share:		
Authorized – 7,600,000 Shares		
Outstanding – 7,536,640 Shares	135,660	135,660
Paid-in Capital	674,606	674,979
Retained Earnings	1,029,915	868,840
Accumulated Other Comprehensive Income (Loss)	(26,815)	(12,491)
TOTAL COMMON SHAREHOLDER'S EQUITY	1,813,366	1,666,988
Noncontrolling Interest	391	361
TOTAL EQUITY	1,813,757	1,667,349
TOTAL LIABILITIES AND EQUITY	$ 5,601,783	$ 5,243,567

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 225.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2011, 2010 and 2009
(in thousands)

	2011	2010	2009
OPERATING ACTIVITIES			
Net Income	$ 165,126	$ 146,684	$ 117,203
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	133,229	126,901	145,144
Deferred Income Taxes	16,726	81,764	28,016
Extraordinary Item, Net of Tax	-	-	5,325
Asset Impairment and Other Related Charges	49,000	-	-
Allowance for Equity Funds Used During Construction	(48,731)	(45,646)	(46,737)
Mark-to-Market of Risk Management Contracts	1,732	4,826	650
Pension Contributions to Qualified Plan Trust	(31,263)	(29,065)	-
Fuel Over/Under-Recovery, Net	(21,485)	(6,089)	68,024
Change in Regulatory Liabilities	28,031	26,671	(2,310)
Change in Other Noncurrent Assets	24,519	(15,207)	20,333
Change in Other Noncurrent Liabilities	20,904	21,958	9,111
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	20,751	(21,507)	113,134
Fuel, Materials and Supplies	(15,168)	21,498	(26,190)
Accounts Payable	1,168	(23,004)	40,981
Accrued Taxes, Net	40,189	(18,788)	(25,252)
Accrued Interest	(910)	6,570	(3,468)
Other Current Assets	2,983	(3,182)	700
Other Current Liabilities	340	(1,433)	(33,844)
Net Cash Flows from Operating Activities	387,141	272,951	410,820
INVESTING ACTIVITIES			
Construction Expenditures	(551,163)	(420,485)	(596,581)
Change in Advances to Affiliates, Net	86,222	(34,405)	(34,883)
Equity Investments	(1,460)	(200)	(12,873)
Acquisitions of Assets	(8,045)	(103,225)	(17,639)
Proceeds from Sales of Assets	1,197	5,356	105,999
Other Investing Activities	2,365	(211)	(510)
Net Cash Flows Used for Investing Activities	(470,884)	(553,170)	(556,487)
FINANCING ACTIVITIES			
Capital Contribution from Parent	-	-	142,500
Issuance of Long-term Debt – Nonaffiliated	-	399,394	-
Credit Facility Borrowings	58,435	99,688	126,903
Change in Advances from Affiliates, Net	132,473	-	(2,526)
Retirement of Long-term Debt – Nonaffiliated	(41,135)	(53,500)	(4,406)
Retirement of Long-term Debt – Affiliated	-	(50,000)	-
Retirement of Cumulative Preferred Stock	(5,069)	(1)	-
Credit Facility Repayments	(47,636)	(100,361)	(127,185)
Proceeds from Sale/Leaseback	-	-	22,831
Principal Payments for Capital Lease Obligations	(13,675)	(12,183)	(10,952)
Dividends Paid on Common Stock – Nonaffiliated	(3,811)	(3,763)	(3,375)
Dividends Paid on Cumulative Preferred Stock	(210)	(229)	(229)
Other Financing Activities	3,658	1,027	1,857
Net Cash Flows from Financing Activities	83,030	280,072	145,418
Net Decrease in Cash and Cash Equivalents	(713)	(147)	(249)
Cash and Cash Equivalents at Beginning of Period	1,514	1,661	1,910
Cash and Cash Equivalents at End of Period	$ 801	$ 1,514	$ 1,661
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 71,713	$ 70,729	$ 80,671
Net Cash Paid (Received) for Income Taxes	(336)	8,350	19,615
Noncash Acquisitions Under Capital Leases	13,334	1,593	51,217
Construction Expenditures Included in Current Liabilities at December 31,	109,600	94,836	71,431
Noncash Assumption of Liabilities Related to Acquisitions of Assets	-	8,400	-

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 225.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
INDEX OF NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to SWEPCo's financial statements are combined with the notes to financial statements for other registrant subsidiaries. Listed below are the notes that apply to SWEPCo. The footnotes begin on page 225.

INDEX OF NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to financial statements that follow are a combined presentation for the Registrant Subsidiaries. The following list indicates the registrants to which the footnotes apply:

1.	Organization and Summary of Significant Accounting Policies	APCo, I&M, OPCo, PSO, SWEPCo
2.	New Accounting Pronouncements and Extraordinary Item	APCo, I&M, OPCo, PSO, SWEPCo
3.	Rate Matters	APCo, I&M, OPCo, PSO, SWEPCo
4.	Effects of Regulation	APCo, I&M, OPCo, PSO, SWEPCo
5.	Commitments, Guarantees and Contingencies	APCo, I&M, OPCo, PSO, SWEPCo
6.	Acquisitions and Impairments	APCo, OPCo, SWEPCo
7.	Benefit Plans	APCo, I&M, OPCo, PSO, SWEPCo
8.	Business Segments	APCo, I&M, OPCo, PSO, SWEPCo
9.	Derivatives and Hedging	APCo, I&M, OPCo, PSO, SWEPCo
10.	Fair Value Measurements	APCo, I&M, OPCo, PSO, SWEPCo
11.	Income Taxes	APCo, I&M, OPCo, PSO, SWEPCo
12.	Leases	APCo, I&M, OPCo, PSO, SWEPCo
13.	Financing Activities	APCo, I&M, OPCo, PSO, SWEPCo
14.	Related Party Transactions	APCo, I&M, OPCo, PSO, SWEPCo
15.	Property, Plant and Equipment	APCo, I&M, OPCo, PSO, SWEPCo
16.	Cost Reduction Initiatives	APCo, I&M, OPCo, PSO, SWEPCo
17.	Unaudited Quarterly Financial Information	APCo, I&M, OPCo, PSO, SWEPCo

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

The principal business conducted by the Registrant Subsidiaries is the generation, transmission and distribution of electric power. These companies are subject to regulation by the FERC under the Federal Power Act and the Energy Policy Act of 2005 and maintain accounts in accordance with the FERC and other regulatory guidelines. These companies are subject to further regulation with regard to rates and other matters by state regulatory commissions.

The Registrant Subsidiaries also engage in wholesale electricity marketing and risk management activities in the United States. I&M provides barging services to both affiliated and nonaffiliated companies. SWEPCo, through consolidated and nonconsolidated affiliates, conducts lignite mining operations to fuel certain of its generation facilities.

CSPCo-OPCo Merger

On December 31, 2011, CSPCo was merged into OPCo with OPCo being the surviving entity. All prior reported amounts have been recast as if the merger occurred on the first day of the earliest reporting period. All contracts and operations of CSPCo and its subsidiary are now part of OPCo.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

The Registrant Subsidiaries' rates are regulated by the FERC and state regulatory commissions in the nine state operating territories in which they operate. The FERC also regulates the Registrant Subsidiaries' affiliated transactions, including AEPSC intercompany service billings which are generally at cost, under the 2005 Public Utility Holding Company Act and the Federal Power Act. The FERC also has jurisdiction over the issuances and acquisitions of securities of the public utility subsidiaries, the acquisition or sale of certain utility assets and mergers with another electric utility or holding company. For non-power goods and services, the FERC requires that a nonregulated affiliate can bill an affiliated public utility company no more than market while a public utility must bill the higher of cost or market to a nonregulated affiliate. The state regulatory commissions also regulate certain intercompany transactions under various orders and affiliate statutes. Both the FERC and state regulatory commissions are permitted to review and audit the relevant books and records of companies within a public utility holding company system.

The FERC regulates wholesale power markets and wholesale power transactions. The Registrant Subsidiaries' wholesale power transactions are generally market-based. Wholesale power transactions are cost-based regulated when the Registrant Subsidiaries negotiate and file a cost-based contract with the FERC or the FERC determines that the Registrant Subsidiaries have "market power" in the region where the transaction occurs. The Registrant Subsidiaries have entered into wholesale power supply contracts with various municipalities and cooperatives that are FERC-regulated, cost-based contracts. These contracts are generally formula rate mechanisms, which are trued up to actual costs annually. PSO's and SWEPCo's wholesale power transactions in the SPP region are cost-based due to PSO and SWEPCo having market power in the SPP region.

The state regulatory commissions regulate all of the retail distribution operations and rates of the Registrant Subsidiaries on a cost basis. The state regulatory commissions also regulate the retail generation/power supply operations and rates except in Ohio. The ESP rates in Ohio continue the process of aligning generation/power supply rates over time with market rates. SWEPCo operates in the SPP area which includes a portion of Texas. In 2009, the Texas legislature amended its restructuring legislation for the generation portion of SWEPCo's Texas retail jurisdiction to delay indefinitely restructuring requirements. As a result, SWEPCo reapplied accounting guidance for "Regulated Operations" to its Texas generation operations.

The FERC also regulates the Registrant Subsidiaries' wholesale transmission operations and rates. The FERC claims jurisdiction over retail transmission rates when retail rates are unbundled in connection with restructuring. OPCo's retail transmission rates in Ohio, APCo's retail transmission rates in Virginia and I&M's retail transmission rates in Michigan are unbundled and are based on the FERC's Open Access Transmission Tariff (OATT) rates that are cost-based. Bundled retail transmission rates are regulated, on a cost basis, by the state commissions.

In addition, the FERC regulates the SIA, the Interconnection Agreement, the CSW Operating Agreement, the System Transmission Integration Agreement, the Transmission Agreement, the Transmission Coordination Agreement and the AEP System Interim Allowance Agreement, all of which allocate shared system costs and revenues to the Registrant Subsidiaries that are parties to each agreement.

Principles of Consolidation

The consolidated financial statements for APCo include the Registrant Subsidiary and its wholly-owned subsidiaries. The consolidated financial statements for I&M include the Registrant Subsidiary, its wholly-owned subsidiaries and DCC Fuel (substantially-controlled variable interest entities (VIEs)). The consolidated financial statements for OPCo include the Registrant Subsidiary and a wholly-owned subsidiary. The consolidated financial statements for SWEPCo include the Registrant Subsidiary, its wholly-owned subsidiaries excluding DHLC (as of January 1, 2010, SWEPCo is no longer the primary beneficiary of DHLC and is no longer required to consolidate DHLC, in accordance with the accounting guidance for "Consolidations") and Sabine (a substantially-controlled VIE). Intercompany items are eliminated in consolidation. The Registrant Subsidiaries use the equity method of accounting for equity investments where they exercise significant influence but do not hold a controlling financial interest. Such investments are recorded as Deferred Charges and Other Noncurrent Assets on the balance sheets; equity earnings are included in Equity Earnings of Unconsolidated Subsidiaries on the statements of income. OPCo, PSO and SWEPCo have ownership interests in generating units that are jointly-owned with nonaffiliated companies. The proportionate share of the operating costs associated with such facilities is included in the income statements and the assets and liabilities are reflected in the balance sheets. See "Variable Interest Entities" section of Note 14.

Accounting for the Effects of Cost-Based Regulation

As rate-regulated electric public utility companies, the Registrant Subsidiaries' financial statements reflect the actions of regulators that result in the recognition of certain revenues and expenses in different time periods than enterprises that are not rate-regulated. In accordance with accounting guidance for "Regulated Operations," the Registrant Subsidiaries record regulatory assets (deferred expenses) and regulatory liabilities (future revenue reductions or refunds) to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues and income with its passage to customers through the reduction of regulated revenues. Due to the passage of legislation requiring restructuring and a transition to customer choice and market-based rates, OPCo discontinued the application of "Regulated Operations" accounting treatment for the generation portion of its business. In 2009, the Texas legislature amended its restructuring legislation for the generation portion of SWEPCo's Texas retail jurisdiction to delay indefinitely restructuring requirements. As a result, SWEPCo reapplied accounting guidance for "Regulated Operations" to its Texas generation operations.

Accounting guidance for "Discontinuation of Rate-Regulated Operations" requires the recognition of an impairment of stranded net regulatory assets and stranded plant costs if they are not recoverable in regulated rates. In addition, an enterprise is required to eliminate from its balance sheet the effects of any actions of regulators that had been recognized as regulatory assets and regulatory liabilities. Such impairments and adjustments are classified as an extraordinary item.

Use of Estimates

The preparation of these financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. These estimates include, but are not limited to, inventory valuation, allowance for doubtful accounts, long-lived asset impairment, unbilled electricity revenue, valuation of long-term energy contracts, the effects of regulation, long-lived asset recovery, storm costs, the effects of contingencies and certain assumptions made in accounting for pension and postretirement benefits. The estimates and assumptions used are based upon management's evaluation of the relevant facts and circumstances as of the date of the financial statements. Actual results could ultimately differ from those estimates.

Cash and Cash Equivalents

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

Inventory

Fossil fuel inventories are generally carried at average cost. Materials and supplies inventories are carried at average cost.

Accounts Receivable

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

Revenue is recognized from electric power sales when power is delivered to customers. To the extent that deliveries have occurred but a bill has not been issued, the Registrant Subsidiaries accrue and recognize, as Accrued Unbilled Revenues on the balance sheets, an estimate of the revenues for energy delivered since the last billing.

AEP Credit factors accounts receivable on a daily basis, excluding receivables from risk management activities, through purchase agreements with I&M, KGPCo, KPCo, OPCo, PSO, SWEPCo and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in its West Virginia regulatory jurisdiction, only a portion of APCo's accounts receivable are sold to AEP Credit. See "Sale of Receivables – AEP Credit" section of Note 13 for additional information.

Allowance for Uncollectible Accounts

Generally, AEP Credit records bad debt expense related to receivables purchased from the Registrant Subsidiaries under a sale of receivables agreement. For receivables related to APCo's West Virginia operations, the bad debt reserve is calculated based on a rolling two-year average write-off in proportion to gross accounts receivable. For customer accounts receivables relating to risk management activities, accounts receivables are reviewed for bad debt reserves at a specific counterparty level basis. For miscellaneous accounts receivable, bad debt expense is recorded for all amounts outstanding 180 days or greater at 100%, unless specifically identified. Miscellaneous accounts receivable items open less than 180 days may be reserved using specific identification for bad debt reserves.

Concentrations of Credit Risk and Significant Customers

The Registrant Subsidiaries do not have any significant customers that comprise 10% or more of their Operating Revenues as of December 31, 2011.

The Registrant Subsidiaries monitor credit levels and the financial condition of their customers on a continuing basis to minimize credit risk. The regulatory commissions allow recovery in rates for a reasonable level of bad debt costs. Management believes adequate provisions for credit loss have been made in the accompanying Registrant Subsidiary financial statements.

Emission Allowances

The Registrant Subsidiaries in regulated jurisdictions record emission allowances at cost, including the annual SO_2 and NO_x emission allowance entitlements received at no cost from the Federal EPA. OPCo records allowances at the lower of cost or market for the period after our FAC expires in May 2015. The Registrant Subsidiaries follow the inventory model for these allowances. Allowances expected to be consumed within one year are reported in Materials and Supplies. Allowances with expected consumption beyond one year are included in Deferred Charges and Other Noncurrent Assets. These allowances are consumed in the production of energy and are recorded in Fuel and Other Consumables Used for Electric Generation at an average cost. Allowances held for speculation are included in Prepayments and Other Current Assets. The purchases and sales of allowances are reported in the Operating Activities section of the statements of cash flows. The net margin on sales of emission allowances is included in Electric Generation, Transmission and Distribution Revenues for nonaffiliated transactions and in Sales to AEP Affiliates Revenues for affiliated transactions because of its integral nature to the production process of energy and the Registrant Subsidiaries' revenue optimization strategy for their operations. The net margin on sales of emission allowances affects the determination of deferred fuel or deferred emission allowance costs and the amortization of regulatory assets for certain jurisdictions.

Property, Plant and Equipment and Equity Investments

Regulated

Electric utility property, plant and equipment for rate-regulated operations are stated at original purchase cost. Additions, major replacements and betterments are added to the plant accounts. Normal and routine retirements from the plant accounts, net of salvage, are charged to accumulated depreciation under the group composite method of depreciation. The group composite method of depreciation assumes that on average, asset components are retired at the end of their useful lives and thus there is no gain or loss. The equipment in each primary electric plant account is identified as a separate group. Under the group composite method of depreciation, continuous interim routine replacements of items such as boiler tubes, pumps, motors, etc. result in the original cost, less salvage, being charged to accumulated depreciation. The depreciation rates that are established take into account the past history of interim capital replacements and the amount of salvage received. These rates and the related lives are subject to periodic review. Removal costs are charged to regulatory liabilities. The costs of labor, materials and overhead incurred to operate and maintain plants are included in operating expenses.

Long-lived assets are required to be tested for impairment when it is determined that the carrying value of the assets may no longer be recoverable or when the assets meet the held-for-sale criteria under the accounting guidance for "Impairment or Disposal of Long-Lived Assets." When it becomes probable that an asset in service or an asset under construction will be abandoned and regulatory cost recovery has been disallowed, the cost of that asset shall be removed from plant-in-service or CWIP and charged to expense. Equity investments are required to be tested for impairment when it is determined there may be an other-than-temporary loss in value.

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

Nonregulated

The generation operations of OPCo and the mining operations of SWEPCo generally follow the policies of cost-based rate-regulated operations listed above but with the following exceptions. Property, plant and equipment are stated at fair value at acquisition (or as adjusted for any applicable impairments) plus the original cost of property acquired or constructed since the acquisition, less disposals. Normal and routine retirements from the plant accounts, net of salvage, are charged to accumulated depreciation for most nonregulated operations under the group composite method of depreciation. A gain or loss would be recorded if the retirement is not considered an interim routine replacement. Removal costs are charged to expense.

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

AFUDC represents the estimated cost of borrowed and equity funds used to finance construction projects that is capitalized and recovered through depreciation over the service life of regulated electric utility plant. For nonregulated operations, including generating assets owned by OPCo and mining operations at SWEPCo, interest is capitalized during construction in accordance with the accounting guidance for "Capitalization of Interest." The Registrant Subsidiaries record the equity component of AFUDC in Allowance for Equity Funds Used During Construction and the debt component of AFUDC as a reduction to Interest Expense.

Valuation of Nonderivative Financial Instruments

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

Fair Value Measurements of Assets and Liabilities

The accounting guidance for "Fair Value Measurements and Disclosures" establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. When quoted market prices are not available, pricing may be completed using comparable securities, dealer values, operating data and general market conditions to determine fair value. Valuation models utilize various inputs such as commodity, interest rate and, to a lesser degree, volatility and credit that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability.

For commercial activities, exchange traded derivatives, namely futures contracts, are generally fair valued based on unadjusted quoted prices in active markets and are classified as Level 1. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, as well as exchange traded contracts where there is insufficient market liquidity to warrant inclusion in Level 1. Management verifies price curves using these broker quotes and classifies these fair values within Level 2 when substantially all of the fair value can be corroborated. Management typically obtains multiple broker quotes, which are non-binding in nature but are based on recent trades in the marketplace. When multiple broker quotes are obtained, the quoted bid and ask prices are averaged. In certain circumstances, a broker quote may be discarded if it is a clear outlier. Management uses a historical correlation analysis between the broker quoted location and the illiquid locations and if the points are highly correlated, these locations are included within Level 2 as well. Certain OTC and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. Long-dated and illiquid complex or structured transactions and FTRs can introduce the need for internally developed modeling inputs based upon extrapolations and assumptions of observable market data to estimate fair value. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized as Level 3.

AEP utilizes its trustee's external pricing service to estimate the fair value of the underlying investments held in the benefit plan and nuclear trusts. AEP's investment managers review and validate the prices utilized by the trustee to determine fair value. AEP's management performs its own valuation testing to verify the fair values of the securities. AEP receives audit reports of the trustee's operating controls and valuation processes. The trustee uses multiple pricing vendors for the assets held in the trusts.

Assets in the benefits and nuclear trusts and Other Cash Deposits are classified using the following methods. Equities are classified as Level 1 holdings if they are actively traded on exchanges. Items classified as Level 1 are investments in money market funds, fixed income and equity mutual funds and domestic equity securities. They are valued based on observable inputs primarily unadjusted quoted prices in active markets for identical assets. Items classified as Level 2 are primarily investments in individual fixed income securities and cash equivalents funds. Fixed income securities do not trade on an exchange and do not have an official closing price but their valuation inputs are based on observable market data. Pricing vendors calculate bond valuations using financial models and matrices. The models use observable inputs including yields on benchmark securities, quotes by securities brokers, rating agency actions, discounts or premiums on securities compared to par prices, changes in yields for U.S. Treasury securities, corporate actions by bond issuers, prepayment schedules and histories, economic events and, for certain securities, adjustments to yields to reflect changes in the rate of inflation. Other securities with model-derived valuation inputs that are observable are also classified as Level 2 investments. Investments with unobservable valuation inputs are classified as Level 3 investments. Benefit plan assets included in Level 3 are primarily real estate and private equity investments that are valued using methods requiring judgment including appraisals.

Deferred Fuel Costs

The cost of fuel and related emission allowances and emission control chemicals/consumables is charged to Fuel and Other Consumables Used for Electric Generation expense when the fuel is burned or the allowance or consumable is utilized. The cost of fuel also includes the cost of nuclear fuel burned which is computed primarily on the units-of-production method. In regulated jurisdictions with an active FAC, fuel cost over-recoveries (the excess of fuel revenues billed to customers over applicable fuel costs incurred) are generally deferred as current regulatory liabilities and under-recoveries (the excess of applicable fuel costs incurred over fuel revenues billed to customers) are generally deferred as current regulatory assets. These deferrals are amortized when refunded or when billed to customers in later months with the state regulatory commissions' review and approval. The amount of an over-recovery or under-recovery can also be affected by actions of the state regulatory commissions. On a routine basis, state regulatory commissions review and/or audit the Registrant Subsidiaries' fuel procurement policies and practices, the fuel cost calculations and FAC deferrals. When a fuel cost disallowance becomes probable, the Registrant Subsidiaries adjust their FAC deferrals and record provisions for estimated refunds to recognize these probable outcomes. Fuel cost over-recovery and under-recovery balances are classified as noncurrent when there is a phase-in plan or the FAC has been suspended or terminated.

Changes in fuel costs, including purchased power in Indiana and Michigan for I&M, in Ohio (beginning in 2012 through May 2015) for OPCo, in Arkansas, Louisiana and Texas for SWEPCo, in Oklahoma for PSO and in Virginia for APCo are reflected in rates in a timely manner through the FAC. Changes in fuel costs, including purchased power in Ohio (beginning in 2009 through 2011) for OPCo and in West Virginia for APCo are reflected in rates through FAC phase-in plans. The FAC generally includes some sharing of off-system sales. In West Virginia for APCo, all of the profits from off-system sales are given to customers through the FAC. None of the profits from off-system sales are given to customers through the FAC in Ohio for OPCo. A portion of profits from off-system sales are given to customers through the FAC and other rate mechanisms in Oklahoma for PSO, Arkansas, Louisiana and Texas for SWEPCo, Virginia for APCo and in Indiana and Michigan (all areas of Michigan beginning in December 2010) for I&M. Where the FAC or off-system sales sharing mechanism is capped, frozen or non-existent, changes in fuel costs or sharing of off-system sales impacted earnings.

Revenue Recognition

Regulatory Accounting

The financial statements of the Registrant Subsidiaries reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated. Regulatory assets (deferred expenses) and regulatory liabilities (deferred revenue reductions or refunds) are recorded to reflect the economic effects of regulation in the same accounting period by matching expenses with their recovery through regulated revenues and by matching income with its passage to customers in cost-based regulated rates.

When regulatory assets are probable of recovery through regulated rates, the Registrant Subsidiaries record them as assets on the balance sheets. The Registrant Subsidiaries test for probability of recovery at each balance sheet date or whenever new events occur. Examples of new events include the issuance of a regulatory commission order or passage of new legislation. If it is determined that recovery of a regulatory asset is no longer probable, the Registrant Subsidiaries write off that regulatory asset as a charge against income.

Traditional Electricity Supply and Delivery Activities

The Registrant Subsidiaries recognize revenues from retail and wholesale electricity sales and electricity transmission and distribution delivery services. The Registrant Subsidiaries recognize the revenues on the statements of income upon delivery of the energy to the customer and include unbilled as well as billed amounts. In accordance with the applicable state commission regulatory treatment, PSO and SWEPCo do not record the fuel portion of unbilled revenue.

Most of the power produced at the generation plants of the AEP East companies is sold to PJM, the RTO operating in the east service territory. The AEP East companies purchase power from PJM to supply power to their customers. Generally, these power sales and purchases are reported on a net basis as revenues on the statements of income. However, purchases of power in excess of sales to PJM, on an hourly net basis, used to serve retail load are recorded gross as Purchased Electricity for Resale on the statements of income. Other RTOs in which the Registrant Subsidiaries participate do not function in the same manner as PJM. They function as balancing organizations and not as exchanges.

Physical energy purchases arising from non-derivative contracts are accounted for on a gross basis in Purchased Electricity for Resale on the statements of income. Energy purchases arising from non-trading derivative contracts are recorded based on the transaction's economic substance. Purchases under non-trading derivatives used to serve accrual based obligations are recorded in Purchased Electricity for Resale on the statements of income. All other non-trading derivative purchases are recorded net in revenues.

In general, the Registrant Subsidiaries record expenses when purchased electricity is received and when expenses are incurred, with the exception of certain power purchase contracts that are derivatives and accounted for using MTM accounting where generation/supply rates are not cost-based regulated, such as in Ohio for OPCo and until April 2009 in Texas for SWEPCo. In jurisdictions where the generation/supply business is subject to cost-based regulation, the unrealized MTM amounts are deferred as regulatory assets (for losses) and regulatory liabilities (for gains).

Energy Marketing and Risk Management Activities

AEPSC, on behalf of the Registrant Subsidiaries, engages in wholesale electricity, coal, natural gas and emission allowances marketing and risk management activities focused on wholesale markets where the AEP System owns assets and adjacent markets. These activities include the purchase and sale of energy under forward contracts at fixed and variable prices and the buying and selling of financial energy contracts which include exchange traded futures and options, as well as OTC options and swaps. Certain energy marketing and risk management transactions are with RTOs.

The Registrant Subsidiaries recognize revenues and expenses from wholesale marketing and risk management transactions that are not derivatives upon delivery of the commodity. The Registrant Subsidiaries use MTM accounting for wholesale marketing and risk management transactions that are derivatives unless the derivative is designated in a qualifying cash flow hedge relationship or a normal purchase or sale. The Registrant Subsidiaries include realized gains and losses on wholesale marketing and risk management transactions in revenues on a net basis. For OPCo, the unrealized gains and losses on wholesale marketing and risk management transactions that are accounted for using MTM are included in revenues on a net basis. For APCo, I&M, PSO and SWEPCo, who are subject to cost-based regulation, the unrealized MTM amounts and some realized gains and losses are deferred as regulatory assets (for losses) and regulatory liabilities (for gains). Unrealized MTM gains and losses are included on the balance sheets as Risk Management Assets or Liabilities as appropriate.

Certain qualifying wholesale marketing and risk management derivatives transactions are designated as hedges of variability in future cash flows as a result of forecasted transactions (cash flow hedge). The Registrant Subsidiaries initially record the effective portion of the cash flow hedge's gain or loss as a component of AOCI. When the forecasted transaction is realized and affects net income, the Registrant Subsidiaries subsequently reclassify the gain or loss on the hedge from AOCI into revenues or expenses within the same financial statement line item as the forecasted transaction on their statements of income. For OPCo, the ineffective portion of the gain or loss is recognized in revenues or expense on the income statements immediately. APCo, I&M, PSO, and SWEPCo, who are subject to cost-based regulation, defer the ineffective portion as regulatory assets (for losses) and regulatory liabilities (for gains). See "Accounting for Cash Flow Hedging Strategies" section of Note 9.

Levelization of Nuclear Refueling Outage Costs

In accordance with regulatory orders, I&M defers incremental operation and maintenance costs associated with periodic refueling outages at its Cook Plant and amortizes the costs over the period beginning with the month following the start of each unit's refueling outage and lasting until the end of the month in which the same unit's next scheduled refueling outage begins. I&M adjusts the amortization amount as necessary to ensure full amortization of all deferred costs by the end of the refueling cycle.

Maintenance

The Registrant Subsidiaries expense maintenance costs as incurred. If it becomes probable that the Registrant Subsidiaries will recover specifically-incurred costs through future rates, a regulatory asset is established to match the expensing of those maintenance costs with their recovery in cost-based regulated revenues. In certain regulatory jurisdictions, the Registrant Subsidiaries defer costs above the level included in base rates and amortize those deferrals commensurate with recovery through rate riders.

Income Taxes and Investment Tax Credits

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

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

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

The Registrant Subsidiaries account for uncertain tax positions in accordance with the accounting guidance for "Income Taxes." The Registrant Subsidiaries classify interest expense or income related to uncertain tax positions as interest expense or income as appropriate and classify penalties as Other Operation.

Excise Taxes

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

Government Grants

For APCo's commercial scale Carbon Capture and Sequestration facility at the Mountaineer Plant and OPCo's gridSMART® demonstration program, APCo and OPCo are reimbursed by the Department of Energy for allowable costs incurred during the billing period. These reimbursements result in the reduction of Other Operation and Maintenance expenses on the statements of income or a reduction in Construction Work in Progress on the balance sheets.

Debt

Gains and losses from the reacquisition of debt used to finance regulated electric utility plants are deferred and amortized over the remaining term of the reacquired debt in accordance with their rate-making treatment unless the debt is refinanced. If the reacquired debt associated with the regulated business is refinanced, the reacquisition costs attributable to the portions of the business that are subject to cost-based regulatory accounting are generally deferred and amortized over the term of the replacement debt consistent with its recovery in rates. Some jurisdictions require that these costs be expensed upon reacquisition. The Registrant Subsidiaries report gains and losses on the reacquisition of debt for operations that are not subject to cost-based rate regulation in Interest Expense.

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

Investments Held in Trust for Future Liabilities

AEP has several trust funds with significant investments intended to provide for future payments of pension and OPEB benefits, nuclear decommissioning and spent nuclear fuel disposal. All of the trust funds' investments are diversified and managed in compliance with all laws and regulations. The investment strategy for trust funds is to use a diversified portfolio of investments to achieve an acceptable rate of return while managing the interest rate sensitivity of the assets relative to the associated liabilities. To minimize investment risk, the trust funds are broadly diversified among classes of assets, investment strategies and investment managers. Management regularly reviews the actual asset allocations and periodically rebalances the investments to targeted allocations when appropriate. Investment policies and guidelines allow investment managers in approved strategies to use financial derivatives to obtain or manage market exposures and to hedge assets and liabilities. The investments are reported at fair value under the "Fair Value Measurements and Disclosures" accounting guidance.

Benefit Plans

All benefit plan assets are invested in accordance with each plan's investment policy. The investment policy outlines the investment objectives, strategies and target asset allocations by plan.

The investment philosophies for AEP's benefit plans support the allocation of assets to minimize risks and optimize net returns. Strategies used include:

- Maintaining a long-term investment horizon.
- Diversifying assets to help control volatility of returns at acceptable levels.
- Managing fees, transaction costs and tax liabilities to maximize investment earnings.
- Using active management of investments where appropriate risk/return opportunities exist.
- Keeping portfolio structure style-neutral to limit volatility compared to applicable benchmarks.
- Using alternative asset classes such as real estate and private equity to maximize return and provide additional portfolio diversification.

The investment policy for the pension fund allocates assets based on the funded status of the pension plan. The objective of the asset allocation policy is to reduce the investment volatility of the plan over time. Generally, more of the investment mix will be allocated to fixed income investments as the plan becomes better funded. Assets will be transferred away from equity investments into fixed income investments based on the market value of plan assets compared to the plan's projected benefit obligation. The current target asset allocations are as follows:

Pension Plan Assets	Target
Equity	45.0 %
Fixed Income	45.0 %
Other Investments	10.0 %

OPEB Plans Assets	Target
Equity	66.0 %
Fixed Income	33.0 %
Cash	1.0 %

The investment policy for each benefit plan contains various investment limitations. The investment policies establish concentration limits for securities. Investment policies prohibit the benefit trust funds from purchasing securities issued by AEP (with the exception of proportionate and immaterial holdings of AEP securities in passive index strategies). However, the investment policies do not preclude the benefit trust funds from receiving contributions in the form of AEP securities, provided that the AEP securities acquired by each plan may not exceed the limitations imposed by law. Each investment manager's portfolio is compared to a diversified benchmark index.

For equity investments, the limits are as follows:

- No security in excess of 5% of all equities.
- Cash equivalents must be less than 10% of an investment manager's equity portfolio.
- No individual stock may be more than 10% of each manager's equity portfolio.
- No investment in excess of 5% of an outstanding class of any company.
- No securities may be bought or sold on margin or other use of leverage.

For fixed income investments, the concentration limits must not exceed:

- 3% in one issuer
- 5% private placements
- 5% convertible securities
- 60% for bonds rated AA+ or lower
- 50% for bonds rated A+ or lower
- 10% for bonds rated BBB- or lower

For obligations of non-government issuers, the following limitations apply:

- AAA rated debt: a single issuer should account for no more than 5% of the portfolio.
- AA+, AA, AA- rated debt: a single issuer should account for no more than 3% of the portfolio.
- Debt rated A+ or lower: a single issuer should account for no more than 2% of the portfolio.
- No more than 10% of the portfolio may be invested in high yield and emerging market debt combined at any time.

A portion of the pension assets is invested in real estate funds to provide diversification, add return and hedge against inflation. Real estate properties are illiquid, difficult to value and not actively traded. The pension plan uses external real estate investment managers to invest in commingled funds that hold real estate properties. To mitigate investment risk in the real estate portfolio, commingled real estate funds are used to ensure that holdings are diversified by region, property type and risk classification. Real estate holdings include core, value-added and development risk classifications and some investments in Real Estate Investment Trusts (REITs), which are publicly traded real estate securities classified as Level 1.

A portion of the pension assets is invested in private equity. Private equity investments add return and provide diversification and typically require a long-term time horizon to evaluate investment performance. Private equity is classified as an alternative investment because it is illiquid, difficult to value and not actively traded. The pension plan uses limited partnerships and commingled funds to invest across the private equity investment spectrum. The private equity holdings are with eleven general partners who help monitor the investments and provide investment selection expertise. The holdings are currently comprised of venture capital, buyout and hybrid debt and equity investment instruments. Commingled private equity funds are used to enhance the holdings' diversity.

AEP participates in a securities lending program with BNY Mellon to provide incremental income on idle assets and to provide income to offset custody fees and other administrative expenses. AEP lends securities to borrowers approved by BNY Mellon in exchange for cash collateral. All loans are collateralized by at least 102% of the loaned asset's market value and the cash collateral is invested. The difference between the rebate owed to the borrower and the cash collateral rate of return determines the earnings on the loaned security. The securities lending program's objective is providing modest incremental income with a limited increase in risk.

Trust owned life insurance (TOLI) underwritten by The Prudential Insurance Company is held in the OPEB plan trusts. The strategy for holding life insurance contracts in the taxable Voluntary Employees' Beneficiary Association (VEBA) trust is to minimize taxes paid on the asset growth in the trust. Earnings on plan assets are tax-deferred within the TOLI contract and can be tax-free if held until claims are paid. Life insurance proceeds remain in the trust and are used to fund future retiree medical benefit liabilities. With consideration to other investments held in the trust, the cash value of the TOLI contracts is invested in two diversified funds. A portion is invested in a commingled fund with underlying investments in stocks that are actively traded on major international equity exchanges. The other portion of the TOLI cash value is invested in a diversified, commingled fixed income fund with underlying investments in government bonds, corporate bonds and asset-backed securities.

Cash and cash equivalents are held in each trust to provide liquidity and meet short-term cash needs. Cash equivalent funds are used to provide diversification and preserve principal. The underlying holdings in the cash funds are investment grade money market instruments including commercial paper, certificates of deposit, treasury bills and other types of investment grade short-term debt securities. The cash funds are valued each business day and provide daily liquidity.

Nuclear Trust Funds

Nuclear decommissioning and spent nuclear fuel trust funds represent funds that regulatory commissions allow I&M to collect through rates to fund future decommissioning and spent nuclear fuel disposal liabilities. By rules or orders, the IURC, the MPSC and the FERC established investment limitations and general risk management guidelines. In general, limitations include:

- Acceptable investments (rated investment grade or above when purchased).
- Maximum percentage invested in a specific type of investment.
- Prohibition of investment in obligations of AEP, I&M or their affiliates.
- Withdrawals permitted only for payment of decommissioning costs and trust expenses.

I&M maintains trust funds for each regulatory jurisdiction. The trust assets may not be used for another jurisdiction's liabilities. Regulatory approval is required to withdraw decommissioning funds. These funds are managed by external investment managers who must comply with the guidelines and rules of the applicable regulatory authorities. The trust assets are invested to optimize the net of tax earnings of the trust giving consideration to liquidity, risk, diversification and other prudent investment objectives.

I&M records securities held in these trust funds in Spent Nuclear Fuel and Decommissioning Trusts on its balance sheets. I&M records these securities at fair value. I&M classifies securities in the trust funds as available-for-sale due to their long-term purpose. Other-than-temporary impairments for investments in both debt and equity securities are considered realized losses as a result of securities being managed by an external investment management firm. The external investment management firm makes specific investment decisions regarding the equity and debt investments held in these trusts and generally intends to sell debt securities in an unrealized loss position as part of a tax optimization strategy. Impairments reduce the cost basis of the securities which will affect any future unrealized gain or realized gains or losses due to the adjusted cost of investment. I&M records unrealized gains and other-than-temporary impairments from securities in these trust funds as adjustments to the regulatory liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the SNF disposal trust funds in accordance with their treatment in rates. Consequently, changes in fair value of trust assets do not affect earnings or AOCI. See the "Nuclear Contingencies" section of Note 5 for additional discussion of nuclear matters. See "Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal" section of Note 10 for disclosure of the fair value of assets within the trusts.

Comprehensive Income (Loss)

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

Accumulated Other Comprehensive Income (Loss) (AOCI)

AOCI is included on the balance sheets in the equity section. Components of AOCI for the Registrant Subsidiaries as of December 31, 2011 and 2010 are shown in the following table:

	December 31, 2011	December 31, 2010
	(in thousands)	
Cash Flow Hedges, Net of Tax		
APCo	$ (285)	$ (56)
I&M	(15,284)	(8,685)
OPCo	7,706	10,449
PSO	7,149	8,494
SWEPCo	(15,524)	(4,190)
Amortization of Pension and OPEB Deferred Costs, Net of Tax		
APCo	$ 15,521	$ 12,412
I&M	3,088	2,140
OPCo	32,977	22,031
SWEPCo	4,113	3,602
Pension and OPEB Funded Status, Net of Tax		
APCo	$ (73,779)	$ (60,379)
I&M	(16,025)	(14,344)
OPCo	(238,405)	(212,635)
SWEPCo	(15,404)	(11,903)

Earnings Per Share (EPS)

The Registrant Subsidiaries are wholly-owned subsidiaries of AEP. Therefore, none are required to report EPS.

OPCo Revised Depreciation Rates

Effective December 1, 2011, OPCo revised book depreciation rates for certain of OPCo's generating plants consistent with shortened depreciable lives for the generating units. This change in depreciable lives is expected to result in a $54 million increase in depreciation expense in 2012.

2. NEW ACCOUNTING PRONOUNCEMENTS AND EXTRAORDINARY ITEM

NEW ACCOUNTING PRONOUNCEMENTS

Management reviews the new accounting literature to determine its relevance, if any, to the Registrant Subsidiaries' business. The following represents a summary of final pronouncements that impact the financial statements.

Pronouncements Adopted in 2011

The following standards were adopted during 2011. Consequently, the financial statements reflect their impact. The following paragraphs discuss their impact.

ASU 2011-05 "Presentation of Comprehensive Income" (ASU 2011-05)

The Registrant Subsidiaries adopted ASU 2011-05 effective for the 2011 Annual Report. The standard requires other comprehensive income be presented as part of a single continuous statement of comprehensive income or in a statement of other comprehensive income immediately following the statement of net income.

This standard requires retrospective application to all reporting periods presented in the financial statements. This standard changed the presentation of the financial statements but did not affect the calculation of net income or comprehensive income. The FASB deferred the reclassification adjustment presentation provisions of ASU 2011-05 under the terms in ASU 2011-12, "Comprehensive Income (Topic 220): Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income."

EXTRAORDINARY ITEM

SWEPCo Texas Restructuring

In August 2006, the PUCT adopted a rule extending the delay in implementation of customer choice in SWEPCo's SPP area of Texas until no sooner than January 1, 2011. In May 2009, the governor of Texas signed a bill related to SWEPCo's SPP area of Texas that requires continued cost of service regulation until certain stages have been completed and approved by the PUCT such that fair competition is available to all Texas retail customer classes. Based upon the signing of the bill, SWEPCo re-applied "Regulated Operations" accounting guidance for the generation portion of SWEPCo's Texas retail jurisdiction effective second quarter of 2009. Management believes that a switch to competition in the SPP area of Texas will not occur. The reapplication of "Regulated Operations" accounting guidance resulted in an $8 million ($5 million, net of tax) extraordinary loss.

3. RATE MATTERS

The Registrant Subsidiaries are involved in rate and regulatory proceedings at the FERC and their state commissions. Rate matters can have a material impact on net income, cash flows and possibly financial condition. The Registrant Subsidiaries recent significant rate orders and pending rate filings are addressed in this note.

OPCo Rate Matters

Ohio Electric Security Plan Filing

2009 – 2011 ESP

The PUCO issued an order in March 2009 that modified and approved the ESP which established rates at the start of the April 2009 billing cycle through 2011. OPCo collected the 2009 annualized revenue increase over the last nine months of 2009. The order also provided a phase-in FAC, which was authorized to be recovered through a non-bypassable surcharge over the period 2012 through 2018 or until securitized. The net FAC deferral as of December 31, 2011 was $507 million, excluding unrecognized equity carrying costs. Collection of the FAC began in January 2012. If OPCo is not ultimately permitted to fully recover its FAC deferral, it would reduce future net income and cash flows and impact financial condition. The PUCO's March 2009 order was appealed to the Supreme Court of Ohio, which issued an opinion and remanded certain issues back to the PUCO.

In October 2011, the PUCO issued an order in the remand proceeding. The order required OPCo to cease POLR billings and apply POLR collections since June 2011 first to the FAC deferral with any remaining balance to be credited to OPCo's customers in November and December 2011. As a result, OPCo recorded a pretax write-off of $47 million on the statement of income related to POLR for the period June 2011 through October 2011. OPCo ceased collection of POLR billings in November 2011. The PUCO order also agreed with OPCo's position that the ESP statute provided a legal basis for reflecting an environmental carrying charge in OPCo's base generation rates. In addition, the PUCO rejected the intervenors' proposed adjustments to the FAC deferral balance for POLR charges and environmental carrying charges for the period from April 2009 through May 2011. In February 2012, the Ohio Consumers' Counsel (OCC) and the Industrial Energy Users-Ohio (IEU) filed appeals with the Supreme Court of Ohio challenging various issues, including the PUCO's refusal to order retrospective relief concerning the POLR charges collected during 2009 – 2011 and various aspects of the approved environmental carrying charge, which if ordered could total up to $698 million, excluding carrying costs.

In January 2011, the PUCO issued an order on the 2009 Significantly Excessive Earnings Test (SEET) filing and determined that 2009 earnings exceeded the PUCO determined threshold by 2.13%. As a result, the PUCO ordered a $43 million refund of pretax earnings to customers, which was recorded in OPCo's 2010 statement of income. The PUCO ordered that the significantly excessive earnings be applied first to the FAC deferral, as of the date of the order, with any remaining balance to be credited to customers on a per kilowatt basis. That credit began with the first billing cycle in February 2011 and continued through December 2011. In May 2011, the IEU and the Ohio Energy Group (OEG) filed appeals with the Supreme Court of Ohio challenging the PUCO's SEET decision. The OEG's appeal seeks the inclusion of off-system sales (OSS) in the calculation of SEET, which, if ordered, could require an additional refund of $22 million based on the PUCO approved SEET calculation. The IEU's appeal also sought the inclusion of OSS as well as other items in the determination of SEET, but did not quantify the amount. Management is unable to predict the outcome of the appeals. If the Supreme Court of Ohio ultimately determines that additional amounts should be refunded, it could reduce future net income and cash flows and impact financial condition.

In July 2011, OPCo filed its 2010 SEET filing with the PUCO based upon the approach in the PUCO's 2009 order. Subsequent testimony and legal briefs from intervenors recommended a refund of up to $62 million of 2010 earnings, which included OSS in the SEET calculation. In December 2011, the PUCO staff filed testimony that recommended a $23 million refund of 2010 earnings. In the fourth quarter of 2011, OPCo provided a reserve based upon management's estimate of the probable amount for a PUCO ordered SEET refund.

OPCo is required to file its 2011 SEET filing with the PUCO in 2012. Management does not currently believe that there are significantly excessive earnings in 2011. Management is unable to predict the outcome of the unresolved litigation discussed above. If these proceedings, including future SEET filings, result in adverse rulings, it could reduce future net income and cash flows and impact financial condition.

January 2012 – May 2016 ESP

In January 2011, OPCo filed an application with the PUCO to approve a new ESP that includes a standard service offer (SSO) pricing for generation. The filed ESP also included alternative energy resource requirements and addressed provisions regarding distribution service, energy efficiency requirements, economic development, job retention in Ohio, generation resources and other matters.

In December 2011, a modified stipulation was approved by the PUCO which involved various issues pending before the PUCO. Various parties, including OPCo, filed requests for rehearing with the PUCO. In February 2012, the PUCO issued an entry on rehearing which rejected the modified stipulation and ordered a return to the 2011 ESP rates until a new rate plan is approved. Under the February 2012 rehearing order, OPCo has 30 days to notify the PUCO whether it plans to modify or withdraw its original application as filed in January 2011. Management is currently evaluating its options and the potential financial and operational impacts on OPCo.

2011 Ohio Distribution Base Rate Case

In February 2011, OPCo filed with the PUCO for an annual increase in distribution rates of $94 million based upon an 11.15% return on common equity to be effective January 2012. In December 2011, a stipulation was approved by the PUCO which provided for no change in distribution rates and a new rider for a $15 million annual credit to residential ratepayers due principally to the inclusion of the rate base distribution investment in the Distribution Investment Rider (DIR). See the "January 2012 – May 2016 ESP" section above. The stipulation also approved recovery of certain distribution regulatory assets of $173 million as of December 31, 2011, excluding $154 million of unrecognized equity carrying costs. These assets and unrecognized carrying costs will be recovered in a distribution asset recovery rider over seven years with an additional long term debt carrying charge, effective January 2012.

Due to the February 2012 PUCO ESP entry on rehearing which rejected the modified stipulation for a new ESP, collection of the DIR terminated. OPCo has the right to withdraw from the stipulation in the distribution base rate case. Management is currently evaluating all its options. If OPCo is not ultimately permitted to fully recover its costs and deferrals, it would reduce future net income and cash flows and impact financial condition.

Sporn Unit 5

In October 2010, OPCo filed an application with the PUCO for the approval of a December 2010 closure of Sporn Unit 5 and the simultaneous establishment of a new non-bypassable distribution rider outside the rate caps established in the 2009 – 2011 ESP proceeding.

In the third quarter of 2011, management decided to no longer offer the output of Sporn Unit 5 into the PJM market. Sporn Unit 5 is not expected to operate in the future, resulting in the removal of Sporn Unit 5 from the AEP Power Pool. As a result, in the third quarter of 2011, OPCo recorded a pretax write-off of $48 million in Asset Impairments and Other Related Charges on the statement of income. In January 2012, the PUCO issued an order which denied recovery of a new non-bypassable distribution rider and declined to exercise jurisdiction over the closure of Sporn Unit 5.

2009 Fuel Adjustment Clause Audit

As required under the ESP orders, the PUCO selected an outside consultant to conduct the audit of the FAC for OPCo for the period of January 2009 through December 2009. In May 2010, the outside consultant provided its confidential audit report to the PUCO. The audit report included a recommendation that the PUCO review whether any proceeds from a 2008 coal contract settlement agreement which totaled $72 million should reduce OPCo's FAC under-recovery balance. Of the total proceeds, approximately $58 million was recognized as a reduction to fuel expense prior to 2009 and $14 million was recognized as a reduction to fuel expense in 2009 and 2010, of which approximately $7 million was the retail jurisdictional share which reduced the FAC deferral in 2009 and 2010.

In January 2012, the PUCO ordered that the remaining $65 million in proceeds from the 2008 coal contract settlement be applied against OPCo's under-recovered fuel balance pending a PUCO decision in OPCo's February 2012 rehearing request. OPCo's rehearing request stated that no additional gain should be credited to the FAC or at most only the retail share of the $58 million gain be applied to the FAC, which approximated $30 million. Further, the January 2012 PUCO order stated that a consultant be hired to review the coal reserve valuation and recommend whether any additional value should benefit ratepayers. Management is unable to predict the outcome of the consultant's recommendation. If the PUCO ultimately determines that additional amounts related to the coal reserve valuation should benefit ratepayers, it could reduce future net income and cash flows and impact financial condition.

2010 Fuel Adjustment Clause Audit

In May 2011, the PUCO-selected outside consultant issued its results of the 2010 FAC audit for OPCo. The audit report included a recommendation that the PUCO reexamine the carrying costs on the deferred FAC balance and determine whether the carrying costs on the balance should be net of accumulated income taxes. As of December 31, 2011, the amount of OPCo's carrying costs that could potentially be at risk is estimated to be $15 million, excluding $17 million of unrecognized equity carrying costs. A decision from the PUCO is pending. Management is unable to predict the outcome of this proceeding. If the PUCO order results in a reduction in the carrying charges related to the FAC deferrals, it would reduce future net income and cash flows and impact financial condition.

Ormet Interim Arrangement

OPCo and Ormet, a large aluminum company, filed an application with the PUCO for approval of an interim arrangement governing the provision of generation service to Ormet. This interim arrangement was approved by the PUCO and was effective from January 2009 through September 2009. In March 2009, the PUCO approved a FAC in the ESP filing and the FAC aspect of the ESP order was upheld by the Supreme Court of Ohio. The approval of the FAC as part of the ESP, together with the PUCO approval of the interim arrangement, provided the basis to record a regulatory asset for the difference between the approved market price and the rate paid by Ormet. Through September 2009, the last month of the interim arrangement, OPCo had $64 million of deferred FAC costs related to the interim arrangement, excluding $2 million of unrecognized equity carrying costs. In November 2009, OPCo requested that the PUCO approve recovery of the deferral under the interim agreement plus a weighted average cost of capital carrying charge. The interim arrangement deferral is included in OPCo's FAC phase-in deferral balance. In the ESP proceeding, intervenors requested that OPCo be required to refund the Ormet-related regulatory asset and requested that the PUCO prevent OPCo from collecting the Ormet-related revenues in the future. The PUCO did not take any action on this request in the 2009-2011 ESP proceeding. The intervenors raised the issue again in response to OPCo's November 2009 filing to approve recovery of the deferral under the interim agreement and this issue remains pending before the PUCO. If OPCo is not ultimately permitted to fully recover its requested deferrals under the interim arrangement, it would reduce future net income and cash flows and impact financial condition.

Economic Development Rider

In April 2010, the Industrial Energy Users-Ohio (IEU) filed a notice of appeal of the 2009 PUCO-approved Economic Development Rider (EDR) with the Supreme Court of Ohio. The EDR collects from ratepayers the difference between the standard tariff and lower contract billings to qualifying industrial customers, subject to PUCO approval. In June 2011, the Supreme Court of Ohio affirmed the PUCO's decision and dismissed the IEU's appeal.

In June 2010, the IEU filed a notice of appeal of the 2010 PUCO-approved EDR with the Supreme Court of Ohio raising the same issues as in the 2009 EDR appeal. In addition, the IEU added a claim that OPCo should not be able to take the benefits of the higher ESP rates while simultaneously challenging the ESP orders. In June 2011, the IEU voluntarily dismissed the 2010 EDR appeal issues that were the same issues dismissed by the Supreme Court of Ohio in its 2009 EDR appeal referenced above. In August 2011, the Supreme Court of Ohio affirmed the PUCO's decision on the remaining issues.

Ohio IGCC Plant

In March 2005, OPCo filed an application with the PUCO seeking authority to recover costs of building and operating an IGCC power plant. Through December 31, 2011, OPCo has collected $24 million in pre-construction costs authorized in a June 2006 PUCO order and has incurred pre-construction costs. Intervenors have filed motions with the PUCO requesting all collected pre-construction costs be refunded to Ohio ratepayers with interest.

Management cannot predict the outcome of any cost recovery litigation concerning the Ohio IGCC plant or what effect, if any, such litigation would have on future net income and cash flows. However, if OPCo is required to refund pre-construction costs collected, it could reduce future net income and cash flows and impact financial condition.

SWEPCo Rate Matters

Turk Plant

SWEPCo is currently constructing the Turk Plant, a new base load 600 MW pulverized coal ultra-supercritical generating unit in Arkansas, which is expected to be in service in the fourth quarter of 2012. SWEPCo owns 73% (440 MW) of the Turk Plant and will operate the completed facility. The Turk Plant is currently estimated to cost $1.8 billion, excluding AFUDC, plus an additional $122 million for transmission, excluding AFUDC. SWEPCo's share is currently estimated to cost $1.3 billion, excluding AFUDC, plus the additional $122 million for transmission, excluding AFUDC. As of December 31, 2011, excluding costs attributable to its joint owners and a provision for a Texas capital costs cap, SWEPCo has capitalized approximately $1.4 billion of expenditures (including AFUDC and capitalized interest of $220 million and related transmission costs of $104 million). As of December 31, 2011, the joint owners and SWEPCo have contractual construction obligations of approximately $125 million (including related transmission costs of $8 million). SWEPCo's share of the contractual construction commitments is $94 million.

The APSC granted approval for SWEPCo to build the Turk Plant by issuing a Certificate of Environmental Compatibility and Public Need (CECPN) for the 88 MW SWEPCo Arkansas jurisdictional share of the Turk Plant. Following an appeal by certain intervenors, the Arkansas Supreme Court issued a decision that reversed the APSC's grant of the CECPN. SWEPCo filed a notice with the APSC of its intent to proceed with construction of the Turk Plant but that SWEPCo no longer intends to pursue a CECPN to seek recovery of the originally approved 88 MW portion of Turk Plant costs in Arkansas retail rates.

The PUCT issued an order approving a Certificate of Convenience and Necessity (CCN) for the Turk Plant with the following conditions: (a) a cap on the recovery of jurisdictional capital costs for the Turk Plant based on the previously estimated $1.522 billion projected construction cost, excluding AFUDC and related transmission costs, (b) a cap on recovery of annual CO_2 emission costs at $28 per ton through the year 2030 and (c) a requirement to hold Texas ratepayers financially harmless from any adverse impact related to the Turk Plant not being fully subscribed to by other utilities or wholesale customers. SWEPCo appealed the PUCT's order contending the two cost cap restrictions are unlawful. The Texas Industrial Energy Consumers filed an appeal contending that the PUCT's grant of a conditional CCN for the Turk Plant should be revoked because the Turk Plant is unnecessary to serve retail customers. In February 2010, the Texas District Court affirmed the PUCT's order in all respects. In March 2010, SWEPCo and the Texas Industrial Energy Consumers appealed this decision to the Texas Court of Appeals. In November 2011, the Texas Court of Appeals affirmed the PUCT's order in all respects. As a result, in the fourth quarter of 2011, SWEPCo recorded a pretax write-off of $49 million in Asset Impairment and Other Related Charges on the statement of income related to the estimated excess of the Texas jurisdictional portion of the Turk Plant above the Texas jurisdictional capital costs cap. In December 2011, SWEPCo and the Texas Industrial Energy Consumers filed motions for rehearing at the Texas Court of Appeals which were denied in January 2012. SWEPCo intends to seek review of the Texas Court of Appeals decision at the Supreme Court of Texas.

Several parties, including the Hempstead County Hunting Club (Hunting Club), the Sierra Club and the National Audubon Society had challenged the air permit, the wastewater discharge permit and the wetlands permit that were issued for the Turk Plant. Those parties also sought a temporary restraining order and preliminary injunction to stop construction of the Turk Plant. The motion for preliminary injunction was partially granted in 2010. In 2011, SWEPCo entered into settlement agreements with these parties which resolved all outstanding issues related to the permits and the APSC's grant of a CECPN. The parties dismissed all pending permit and CECPN challenges at the APSC, other administrative agencies and the courts.

If SWEPCo cannot recover all of its investment and expenses related to the Turk Plant, it would materially reduce future net income and cash flows and materially impact financial condition.

Texas Turk Plant Rate Plan

In August 2011, SWEPCo requested approval of a plan from the PUCT for including the Turk Plant investment in Texas retail rates. SWEPCo's application was dismissed in December 2011. The PUCT stated that, as a matter of policy, the PUCT would not order a return on CWIP outside of a full base rate case proceeding. SWEPCo intends to file a full base rate case in 2012 with a proposed rate increase closely aligned with the commercial operation date of the Turk Plant.

Louisiana Fuel Adjustment Clause Audit

Consultants for the LPSC issued their audit report of SWEPCo's Louisiana retail FAC recommending that the LPSC discontinue SWEPCo's tiered sharing mechanism related to the off-system sales margins and reduce the FAC. In April 2011, a settlement agreement was filed with the LPSC which resulted in an immaterial impact for SWEPCo. The settlement agreement deferred the off-system sales issue to SWEPCo's formula rate plan (FRP) extension filing, which was filed in January 2012. In June 2011, the LPSC approved the settlement agreement.

Louisiana 2008 Formula Rate Filing

In April 2008, SWEPCo filed its first formula rate filing under an approved three-year FRP. SWEPCo requested an increase in its annual Louisiana retail rates of $11 million to be effective in August 2008 in order to earn the approved formula return on common equity of 10.565%. In August 2008, as provided by the FRP, SWEPCo implemented the FRP rates, subject to refund. During 2009, SWEPCo recorded a provision for refund of approximately $1 million after reaching a settlement in principle with intervenors. SWEPCo began refunding customers in August 2010. In March 2011, the LPSC approved the settlement stipulation.

Louisiana 2009 Formula Rate Filing

In April 2009, SWEPCo filed the second FRP which would increase its annual Louisiana retail rates by an additional $4 million effective in August 2009. SWEPCo implemented the FRP rate increase as filed in August 2009, subject to refund. Consultants for the LPSC objected to certain components of SWEPCo's FRP calculation. A settlement stipulation was reached by the parties and approved by the LPSC in March 2011. The settlement stipulation provided for a $2 million refund, which was recorded in 2010 as a provision in Other Current Liabilities on SWEPCo's balance sheets. The refund to customers, with interest, began in August 2011.

Louisiana 2010 Formula Rate Filing

In April 2010, SWEPCo filed the third FRP which would decrease its annual Louisiana retail rates by $3 million effective in August 2010 pursuant to the approved FRP, subject to refund. In October 2010 and September 2011, consultants for the LPSC filed testimony objecting to certain components of SWEPCo's FRP calculations. Hearings are scheduled for May 2012. SWEPCo believes the rates as filed are in compliance with the FRP methodology previously approved by the LPSC. If the LPSC disagrees with SWEPCo, it could result in refunds which could reduce future net income and cash flows.

APCo Rate Matters

2011 Virginia Biennial Base Rate Case

In March 2011, APCo filed a generation and distribution base rate request with the Virginia SCC to increase annual base rates by $126 million based upon an 11.65% return on common equity. The return on common equity included a requested 0.5% renewable portfolio standards (RPS) incentive as allowed by law.

In November 2011, the Virginia SCC issued an order which approved a $55 million increase in generation and distribution base rates, effective February 2012, and a 10.9% return on common equity, which included a 0.5% RPS incentive. The $55 million increase included $39 million related to an increase in depreciation rates.

Rate Adjustment Clauses

In 2007, the Virginia law governing the regulation of electric utility service was amended to, among other items, provide for rate adjustment clauses (RACs) beginning in January 2009 for the timely and current recovery of costs of: (a) transmission services billed by an RTO, (b) demand side management and energy efficiency programs, (c) renewable energy programs, (d) environmental compliance projects and (e) new generation facilities, including major unit modifications. In accordance with Virginia law, APCo is deferring incremental environmental costs incurred after December 2008 and renewable energy costs incurred after December 2007 which are not being recovered in current revenues. As of December 31, 2011, APCo has deferred $24 million of environmental costs, excluding $6 million of unrecognized equity carrying costs, incurred from January 2009 through December 2010, $18 million of environmental costs, excluding $4 million of unrecognized equity carrying costs, incurred in 2011 and $44 million of renewable energy costs.

In March 2011, APCo filed for approval of an environmental RAC, a renewable energy program RAC and a generation RAC. The environmental RAC requested recovery of $77 million of incremental environmental compliance costs incurred from January 2009 through December 2010. The renewable energy program RAC requested recovery of $6 million for the incremental portion of deferred wind power costs for the Camp Grove and Fowler Ridge projects through December 2010. The generation RAC requested recovery of the Dresden Plant, which was placed into service in January 2012. With Virginia SCC approval, APCo purchased the Dresden Plant from AEGCo in August 2011 for $302 million.

In August 2011, a stipulation was filed with the Virginia SCC related to the generation RAC. The stipulation requested recovery of the Dresden Plant costs totaling up to $27 million annually, effective March 2012. In January 2012, the Virginia SCC issued an order which modified and approved the stipulation to allow APCo to recover $26 million annually, effective March 2012.

In November 2011, the Virginia SCC issued an order which approved recovery of $6 million for the incremental portion of deferred wind power costs for the Camp Grove and Fowler Ridge projects, effective February 2012. In addition, the order found that APCo can recover the non-incremental deferred wind power costs of $27 million as of December 31, 2011 through the FAC.

Also in November 2011, the Virginia SCC issued an order which approved environmental RAC recovery of $30 million to be collected over one year beginning in February 2012. The Virginia SCC denied recovery of certain environmental costs. As a result, in the fourth quarter of 2011, APCo recorded a pretax write-off of $31 million on the statement of income related to environmental compliance costs incurred from January 2009 through December 2010. In December 2011, APCo filed a notice of appeal with the Supreme Court of Virginia regarding the Virginia SCC's environmental RAC decision. If the Virginia SCC were to disallow a portion of APCo's deferred environmental compliance costs incurred since January 2011, it would reduce future net income and cash flows.

2010 West Virginia Base Rate Case

In May 2010, APCo filed a request with the WVPSC to increase APCo's annual base rates by $140 million based upon an 11.75% return on common equity. In March 2011, the WVPSC modified and approved a settlement agreement which increased annual base rates by approximately $46 million based upon a 10% return on common equity, effective April 2011. The settlement agreement also resulted in a pretax write-off of a portion of the Mountaineer Carbon Capture and Storage Product Validation Facility in March 2011. See "Mountaineer Carbon Capture and Storage Project" section below. In addition, the WVPSC allowed APCo to defer and amortize $18 million of previously expensed 2009 incremental storm expenses and $14 million of previously expensed costs related to the 2010 cost reduction initiatives, each over a period of seven years.

Mountaineer Carbon Capture and Storage Project

Product Validation Facility (PVF)

APCo and ALSTOM Power, Inc., an unrelated third party, jointly constructed a CO_2 capture validation facility, which was placed into service in September 2009. APCo also constructed and owns the necessary facilities to store the CO_2. In October 2009, APCo started injecting CO_2 into the underground storage facilities. The injection of CO_2 required the recording of an asset retirement obligation and an offsetting regulatory asset. In May 2011, the PVF ended operations.

In APCo's May 2010 West Virginia base rate filing, APCo requested rate base treatment of the PVF, including recovery of the related asset retirement obligation regulatory asset amortization and accretion. In March 2011, a WVPSC order denied the request for rate base treatment of the PVF largely due to its experimental operation. The base rate order provided that should APCo construct a commercial scale carbon capture and sequestration (CCS) facility, only the West Virginia portion of the PVF costs, based on load sharing among certain AEP operating companies, may be considered used and useful plant in service and included in future rate base. See "2010 West Virginia Base Rate Case" section above. In 2011, APCo recorded a net pretax write-off of $14 million in Other Operation expense on the statements of income related to the write-off of a portion of the West Virginia jurisdictional share of the PVF offset by an asset retirement obligation adjustment. As of December 31, 2011, APCo has recorded $14 million in Regulatory Assets on the balance sheets related to the PVF. If APCo cannot recover its remaining PVF investment and related accretion expenses, it would reduce future net income and cash flows.

Carbon Capture and Sequestration Project with the Department of Energy (DOE) (Commercial Scale Project)

During 2010, AEPSC, on behalf of APCo, began the project definition stage for the potential construction of a new commercial scale CCS facility at the Mountaineer Plant. The DOE agreed to fund 50% of allowable costs incurred for the CCS facility up to a maximum of $334 million. A Front-End Engineering and Design (FEED) study was completed during the third quarter of 2011. Management postponed any further CCS project activities because of the uncertainty about the regulation of CO_2. In June 2011, the FEED study costs were allocated among the AEP East companies, PSO and SWEPCo based on eligible plants that could potentially benefit from the carbon capture. As of December 31, 2011, the project has incurred $34 million in total project costs and has received $20 million of DOE and other eligible funding resulting in $14 million of net costs, of which $8 million was written off. The remaining $6 million in net costs are recorded in Regulatory Assets on the balance sheets. APCo's, I&M's, and SWEPCo's portions of remaining net costs are as follows:

Company		(in millions)
APCo	$	1.3
I&M		1.7
SWEPCo		2.4

If the costs of the CCS project cannot be recovered, it would reduce future net income and cash flows.

APCo's Filings for an IGCC Plant

Through December 31, 2011, APCo deferred for future recovery pre-construction IGCC costs of approximately $9 million applicable to its West Virginia jurisdiction, approximately $2 million applicable to its FERC jurisdiction and approximately $9 million applicable to its Virginia jurisdiction. APCo will not start construction of the IGCC plant until sufficient assurance of full cost recovery exists in Virginia and West Virginia. If the plant is cancelled, APCo plans to seek recovery of its prudently incurred deferred pre-construction costs. If the costs are not recoverable, it would reduce future net income and cash flows and impact financial condition.