Indiana Michigan
Power Company
Cook Nuclear Plant
500 Circle Drive
Buchanan, MI 49107
616-465-5901

INDIANA
MICHIGAN
POWER

May 17, 2001

C0501-13
10 CFR 50.71
10 CFR 140.21

Docket Nos.: 50-315
50-316

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Mail Stop O-P1-17
Washington, D.C. 20555-0001

Donald C. Cook Nuclear Plant Units 1 and 2
2000 FINANCIAL INFORMATION FOR
INDIANA MICHIGAN POWER COMPANY

Indiana Michigan Power Company (I&M) hereby submits, as Attachment 1, the I&M 2000 Annual Financial Report in accordance with 10 CFR 50.71(b). Also included as Attachment 2 is a copy of the year 2001 projected cash flow for I&M as required by 10 CFR 140.21(e).

Should you have any questions, please contact Mr. Ronald W. Gaston, Manager of Regulatory Affairs, at (616) 697-5020.

Sincerely,

S. A. Greenlee
Director of Design Engineering and Regulatory Affairs

/dmb

Attachments

c: J. E. Dyer
MDEQ – DW & RPD, w/o attachments
NRC Resident Inspector
R. Whale, w/o attachments

M004

ATTACHMENT 1 TO C0501-13

INDIANA MICHIGAN POWER COMPANY
2000 ANNUAL REPORT

Sections B through E and Sections G through K have been omitted from this attachment in order to provide only information relevant to the Licensee, Indiana Michigan Power Company.

# 2000 Annual Reports

American Electric Power Company, Inc.

AEP Generating Company

Appalachian Power Company

Central Power and Light Company

Columbus Southern Power Company

Indiana Michigan Power Company

Kentucky Power Company

Ohio Power Company

Public Service Company of Oklahoma

Southwestern Electric Power Company

West Texas Utilities Company

Audited Financial Statements and
Management's Discussion and Analysis

AEP AMERICAN ELECTRIC POWER

AEP: America's Energy Partner®

## Contents


| | Page |
|---|---|
| Glossary of Terms | i |
| Forward Looking Information | iv |
| **American Electric Power Company, Inc. and Subsidiary Companies** | |
| Selected Consolidated Financial Data | A-1 |
| Management's Discussion and Analysis of Results of Operations | A-2 |
| Consolidated Statements of Income | A-8 |
| Consolidated Balance Sheets | A-9 |
| Consolidated Statements of Cash Flows | A-11 |
| Consolidated Statements of Common Shareholders' Equity | A-12 |
| Schedule of Consolidated Cumulative Preferred Stocks of Subsidiaries | A-13 |
| Schedule of Consolidated Long-term Debt of Subsidiaries | A-14 |
| Index to Notes to Consolidated Financial Statements | A-15 |
| Management's Responsibility | A-16 |
| Independent Auditors' Report | A-17 |
| **AEP Generating Company** | |
| Selected Financial Data | B-1 |
| Management's Narrative Analysis of Results of Operations | B-2 |
| Statements of Income and Statements of Retained Earnings | B-3 |
| Balance Sheets | B-4 |
| Statements of Cash Flows | B-6 |
| Statements of Capitalization | B-7 |
| Index to Notes to Financial Statements | B-8 |
| Independent Auditors' Report | B-9 |
| **Appalachian Power Company and Subsidiaries** | |
| Selected Consolidated Financial Data | C-1 |
| Management's Discussion and Analysis of Results of Operations | C-2 |
| Consolidated Statements of Income | C-5 |
| Consolidated Balance Sheets | C-6 |
| Consolidated Statements of Cash Flows | C-8 |
| Consolidated Statements of Retained Earnings | C-9 |
| Consolidated Statements of Capitalization | C-10 |
| Schedule of Long-term Debt | C-11 |
| Index to Notes to Consolidated Financial Statements | C-12 |
| Independent Auditors' Report | C-13 |

Central Power & Light Company and Subsidiaries
- Selected Consolidated Financial Data D-1
- Management's Discussion and Analysis of Results of Operations D-2
- Consolidated Statements of Income D-5
- Consolidated Balance Sheets D-6
- Consolidated Statements of Cash Flows D-8
- Consolidated Statements of Retained Earnings D-9
- Consolidated Statements of Capitalization D-10
- Schedule of Long-term Debt D-11
- Index to Notes to Consolidated Financial Statements D-12
- Independent Auditors' Report D-13

Columbus Southern Power Company and Subsidiaries
- Selected Consolidated Financial Data E-1
- Management's Narrative Analysis of Results of Operations E-2
- Consolidated Statements of Income and Consolidated Statements of Retained Earnings E-5
- Consolidated Balance Sheets E-6
- Consolidated Statements of Cash Flows E-8
- Consolidated Statements of Capitalization E-9
- Schedule of Long-term Debt E-10
- Index to Notes to Consolidated Financial Statements E-11
- Independent Auditors' Report E-12

Indiana Michigan Power Company and Subsidiaries
- Selected Consolidated Financial Data F-1
- Management's Discussion and Analysis of Results of Operations F-2
- Consolidated Statements of Income F-5
- Consolidated Balance Sheets F-6
- Consolidated Statements of Cash Flows F-8
- Consolidated Statements of Retained Earnings F-9
- Consolidated Statements of Capitalization F-10
- Schedule of Long-term Debt F-11
- Index to Notes to Consolidated Financial Statements F-13
- Independent Auditors' Report F-14

Kentucky Power Company
- Selected Financial Data G-1
- Management's Narrative Analysis of Results of Operations G-2
- Statements of Income and Statements of Retained Earnings G-4
- Balance Sheets G-5
- Statements of Cash Flows G-7
- Statements of Capitalization G-8
- Schedule of Long-term Debt G-9
- Index to Notes to Financial Statements G-10
- Independent Auditors' Report G-11

| | |
|---|---|
| Ohio Power Company and Subsidiaries | |
| Selected Consolidated Financial Data | H-1 |
| Management's Discussion and Analysis of Results of Operations | H-2 |
| Consolidated Statements of Income | H-5 |
| Consolidated Balance Sheets | H-6 |
| Consolidated Statements of Cash Flows | H-8 |
| Consolidated Statements of Retained Earnings | H-9 |
| Consolidated Statements of Capitalization | H-10 |
| Schedule of Long-term Debt | H-11 |
| Index to Notes to Consolidated Financial Statements | H-13 |
| Independent Auditors' Report | H-14 |
| Public Service Company of Oklahoma and Subsidiaries | |
| Selected Consolidated Financial Data | I-1 |
| Management's Narrative Analysis of Results of Operations | I-2 |
| Consolidated Statements of Income and Consolidated Statements of Retained Earnings | I-4 |
| Consolidated Balance Sheets | I-5 |
| Consolidated Statements of Cash Flows | I-7 |
| Consolidated Statements of Capitalization | I-8 |
| Schedule of Long-term Debt | I-9 |
| Index to Notes to Consolidated Financial Statements | I-10 |
| Independent Auditors' Report | I-11 |
| Southwestern Electric Power Company and Subsidiaries | |
| Selected Consolidated Financial Data | J-1 |
| Management's Discussion and Analysis of Results of Operations | J-2 |
| Consolidated Statements of Income and Consolidated Statements of Retained Earnings | J-5 |
| Consolidated Balance Sheets | J-6 |
| Consolidated Statements of Cash Flows | J-8 |
| Consolidated Statements of Capitalization | J-9 |
| Schedule of Long-term Debt | J-10 |
| Index to Notes to Consolidated Financial Statements | J-11 |
| Independent Auditors' Report | J-12 |
| West Texas Utilities Company | |
| Selected Financial Data | K-1 |
| Management's Narrative Analysis of Results of Operations | K-2 |
| Statements of Income and Statements of Retained Earnings | K-4 |
| Balance Sheets | K-5 |
| Statements of Cash Flows | K-7 |
| Statements of Capitalization | K-8 |
| Schedule of Long-term Debt | K-9 |
| Index to Notes to Financial Statements | K-10 |
| Independent Auditors' Report | K-11 |
| Combined Notes to Financial Statements | L-1 |
| Management's Discussion and Analysis of Financial Condition, Contingencies and Other Matters | M-1 |

## GLOSSARY OF TERMS

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

| Term | Meaning |
|---|---|
| 2004 True-up Proceeding | A filing to be made after January 10, 2004 under the Texas Legislation to finalize the amount of stranded costs and the recovery of such costs. |
| AEGCo | AEP Generating Company, an electric utility subsidiary of AEP. |
| AEP | American Electric Power Company, Inc. |
| AEP Consolidated | AEP and its majority owned subsidiaries consolidated. |
| AEP Credit | AEP Credit, Inc., a subsidiary of AEP which factors accounts receivable and accrued utility revenues for affiliated and unaffiliated domestic electric utility companies. |
| AEP East electric operating companies | APCo, CSPCo, I&M, KPCo and OPCo. |
| AEPR | AEP Resources, Inc. |
| AEP System or the System | The American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries. |
| AEPSC | American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries. |
| AEP Power Pool | AEP System Power Pool. Members are APCo, CSPCo, I&M, KPCo and OPCo. The Pool shares the generation, cost of generation and resultant wholesale system sales of the member companies. |
| AEP West electric operating companies | CPL, PSO, SWEPCo and WTU. |
| AFUDC | Allowance for funds used during construction, a noncash nonoperating income item that is capitalized and recovered through depreciation over the service life of domestic regulated electric utility plant. |
| Alliance RTO | Alliance Regional Transmission Organization, an ISO formed by AEP and four unaffiliated utilities. |
| Amos Plant | John E. Amos Plant, a 2,900 MW generation station jointly owned and operated by APCo and OPCo. |
| APCo | Appalachian Power Company, an AEP electric utility subsidiary. |
| Arkansas Commission | Arkansas Public Service Commission. |
| Buckeye | Buckeye Power, Inc., an unaffiliated corporation. |
| CLECO | Central Louisiana Electric Company, Inc., an unaffiliated corporation. |
| COLI | Corporate owned life insurance program. |
| Cook Plant | The Donald C. Cook Nuclear Plant, a two-unit, 2,110 MW nuclear plant owned by I&M. |
| CPL | Central Power and Light Company, an AEP electric utility subsidiary. |
| CSPCo | Columbus Southern Power Company, an AEP electric utility subsidiary. |
| CSW | Central and South West Corporation, a subsidiary of AEP. |
| CSW Energy | CSW Energy, Inc., an AEP subsidiary which invests in energy projects and builds power plants. |
| CSW International | CSW International, Inc., an AEP subsidiary which invests in energy projects and entities outside the United States. |
| D.C. Circuit Court | The United States Court of Appeals for the District of Columbia Circuit. |
| DHMV | Dolet Hills Mining Venture. |
| DOE | United States Department of Energy. |
| ECOM | Excess Cost Over Market. |
| ENEC | Expanded Net Energy Costs. |
| EITF | The Financial Accounting Standards Board's Emerging Issues Task Force. |
| ERCOT | The Electric Reliability Council of Texas. |
| EWGs | Exempt Wholesale Generators. |
| FASB | Financial Accounting Standards Board. |
| Federal EPA | United States Environmental Protection Agency. |

FERC ........................................ Federal Energy Regulatory Commission.
FMB ........................................ First Mortgage Bond.
FUCOs ........................................ Foreign Utility Companies.
GAAP ........................................ Generally Accepted Accounting Principles.
I&M ........................................ Indiana Michigan Power Company, an AEP electric utility subsidiary.
IPC ........................................ Installment Purchase Contract.
IRS ........................................ Internal Revenue Service.
IURC ........................................ Indiana Utility Regulatory Commission.
ISO ........................................ Independent system operator.
Joint Stipulation ........................ Joint Stipulation and Agreement for Settlement of APCo's WV rate proceeding.
KPCo ........................................ Kentucky Power Company, an AEP electric utility subsidiary.
KPSC ........................................ Kentucky Public Service Commission.
KWH ........................................ Kilowatthour.
LIG ........................................ Louisiana Intrastate Gas.
Michigan Legislation .................. The Customer Choice and Electricity Reliability Act, a Michigan law which provides for customer choice of electricity supplier.
Midwest ISO ............................ An independent operator of transmission assets in the Midwest.
MLR ........................................ Member load ratio, the method used to allocate AEP Power Pool transactions to its members.
Money Pool ............................ AEP System's Money Pool.
MPSC ........................................ Michigan Public Service Commission.
MTN ........................................ Medium Term Notes.
MW ........................................ Megawatt.
MWH ........................................ Megawatthour.
NEIL ........................................ Nuclear Electric Insurance Limited.
Nox ........................................ Nitrogen oxide.
Nox Rule ........................................ A final rules issued by Federal EPA which requires NOx reductions in 22 eastern states including seven of the states in which AEP companies operates.
NP ........................................ Notes Payable.
NRC ........................................ Nuclear Regulatory Commission.
Ohio Act ........................................ The Ohio Electric Restructuring Act of 1999.
Ohio EPA ........................................ Ohio Environmental Protection Agency.
OPCo ........................................ Ohio Power Company, an AEP electric utility subsidiary.
OVEC ........................................ Ohio Valley Electric Corporation, an electric utility company in which AEP and CSPCo own a 44.2% equity interest.
PCBs ........................................ Polychlorinated Biphenyls.
PJM ........................................ Pennsylvania – New Jersey – Maryland regional transmission organization.
PRP ........................................ Potentially Responsible Party.
PSO ........................................ Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCO ........................................ The Public Utilities Commission of Ohio.
PUCT ........................................ The Public Utility Commission of Texas.
PUHCA ........................................ Public Utility Holding Company Act of 1935, as amended.
PURPA ........................................ The Public Utility Regulatory Policies Act of 1978.
RCRA ........................................ Resource Conservation and Recovery Act of 1976, as amended.
Registrant Subsidiaries ............ AEP subsidiaries who are SEC registrants; AEGCo, APCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo and WTU.
Rockport Plant ........................ A generating plant, consisting of two 1,300 MW coal-fired generating units near Rockport, Indiana owned by AEGCo and I&M.
RTO ........................................ Regional Transmission Organization.
SEC ........................................ Securities and Exchange Commission.
SFAS ........................................ Statement of Financial Accounting Standards issued by the Financial Accounting Standards Board.

SFAS 71 .................................. Statement of Financial Accounting Standards No. 71, Accounting for the Effects of Certain Types of Regulation.

SFAS 101 ................................ Statement of Financial Accounting Standards No. 101, Accounting for the Discontinuance of Application of Statement 71.

SFAS 121 ................................ Statement of Financial Accounting Standards No. 121, Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed of.

SFAS 133 ................................ Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities.

SNF......................................... Spent Nuclear Fuel.

SPP......................................... Southwest Power Pool.

STP......................................... South Texas Project Nuclear Generating Plant, owned 25.2% by Central Power and Light Company, an AEP electric utility subsidiary .

STPNOC................................. STP Nuclear Operating Company, a non-profit Texas corporation which operates STP on behalf of its joint owners including CPL.

Superfund ................................ The Comprehensive Environmental, Response, Compensation and Liability Act.

SWEPCo.................................. Southwestern Electric Power Company, an AEP electric utility subsidiary.

Texas Appeals Court ............... The Third District of Texas Court of Appeals.

Texas Legislation...................... Legislation enacted in 1999 to restructure the electric utility industry in Texas.

Travis District Court.................. State District Court of Travis County, Texas.

TVA ......................................... Tennessee Valley Authority.

U.K.......................................... The United Kingdom.

UN........................................... Unsecured Note.

VaR.......................................... Value at Risk, a method to quantify risk exposure.

Virginia SCC ............................ Virginia State Corporation Commission.

WV .......................................... West Virginia.

WVPSC.................................... Public Service Commission of West Virginia.

WPCo ...................................... Wheeling Power Company, an AEP electric distribution subsidiary.

WTU......................................... West Texas Utilities Company, an AEP electric utility subsidiary.

Yorkshire.................................. Yorkshire Electricity Group plc, a U.K. regional electricity company owned jointly by AEP and New Century Energies.

Zimmer Plant ........................... William H. Zimmer Generating Station, a 1,300 MW coal-fired unit owned 25.4% by Columbus Southern Power Company, an AEP subsidiary.

## FORWARD LOOKING INFORMATION

This discussion includes forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. These forward-looking statements reflect assumptions, and involve a number of risks and uncertainties. Among the factors both foreign and domestic that could cause actual results to differ materially from forward looking statements are: electric load and customer growth; abnormal weather conditions; available sources of and prices for coal and gas; availability of generating capacity; the impact of the merger with CSW including actual merger savings being less than the related rate reductions; risks related to energy trading and construction under contract; the speed and degree to which competition is introduced to our power generation business; the structure and timing of a competitive market for electricity and its impact on prices; the ability to recover net regulatory assets, other stranded costs and implementation costs in connection with deregulation of generation in certain states; new legislation and government regulations; the ability to successfully control costs; the success of new business ventures; international developments affecting our foreign investments; the economic climate and growth in our service and trading territories both domestic and foreign; the ability of the Company to successfully challenge new environmental regulations and to successfully litigate claims that the Company violated the Clean Air Act; successful resolution of litigation regarding municipal franchise fees in Texas; inflationary trends; changes in electricity and gas market prices; interest rates; foreign exchange rates, and other risks and unforeseen events.

-This page intentionally left blank.-

# AMERICAN ELECTRIC POWER COMPANY, INC.
# AND SUBSIDIARY COMPANIES

## AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
### Selected Consolidated Financial Data

| Year Ended December 31, | 2000 | 1999 | 1998 | 1997 | 1996 |
|---|---|---|---|---|---|
| INCOME STATEMENTS DATA (in millions): | | | | | |
| Total Revenues | $13,694 | $12,407 | $11,840 | $11,163 | $11,017 |
| Operating Income | 2,026 | 2,325 | 2,280 | 2,198 | 2,368 |
| Income From Continuing Operations | 302 | 986 | 975 | 949 | 871 |
| Discontinued Operations | - | - | - | - | 132 |
| Extraordinary Loss | (35) | (14) | - | (285) | - |
| Net Income | 267 | 972 | 975 | 664 | 1,003 |

| December 31, | 2000 | 1999 | 1998 | 1997 | 1996 |
|---|---|---|---|---|---|
| BALANCE SHEETS DATA (in millions): | | | | | |
| Property, Plant and Equipment | $38,088 | $36,938 | $35,655 | $33,496 | $32,443 |
| Accumulated Depreciation and Amortization | 15,695 | 15,073 | 14,136 | 13,229 | 12,494 |
| Net Property, Plant and Equipment | $22,393 | $21,865 | $21,519 | $20,267 | $19,949 |
| Total Assets | $54,548 | $35,719 | $33,418 | $30,092 | $29,228 |
| Common Shareholders' Equity | 8,054 | 8,673 | 8,452 | 8,220 | 8,334 |
| Cumulative Preferred Stocks of Subsidiaries: | | | | | |
| Not Subject to Mandatory Redemption | 61 | 63 | 222 | 223 | 382 |
| Subject to Mandatory Redemption* | 100 | 119 | 128 | 154 | 543 |
| Trust Preferred Securities | 334 | 335 | 335 | 335 | - |
| Long-term Debt* | 10,754 | 11,524 | 11,113 | 9,354 | 9,112 |
| Obligations Under Capital Leases* | 614 | 610 | 539 | 549 | 422 |

*Including portion due within one year

| Year Ended December 31, | 2000 | 1999 | 1998 | 1997 | 1996 |
|---|---|---|---|---|---|
| COMMON STOCK DATA: | | | | | |
| Earnings per Common Share: | | | | | |
| Continuing Operations | $0.94 | $3.07 | $3.06 | $2.99 | $2.79 |
| Discontinued Operations | - | - | - | - | 0.42 |
| Extraordinary Loss | (.11) | (.04) | - | (0.90) | - |
| Net Income | $0.83 | $3.03 | $3.06 | $2.09 | $3.21 |
| Average Number of Shares Outstanding (in millions) | 322 | 321 | 318 | 316 | 312 |
| Market Price Range: High | $48-15/16 | $48-3/16 | $53-5/16 | $ 52 | $44-3/4 |
| Low | 25-15/16 | 30-9/16 | 42-1/16 | 39-1/8 | 38-5/8 |
| Year-end Market Price | 46-1/2 | 32-1/8 | 47-1/16 | 51-5/8 | 41-1/8 |
| Cash Dividends on Common* | $2.40 | $2.40 | $2.40 | $2.40 | $2.40 |
| Dividend Payout Ratio* | 289.2% | 79.2% | 78.4% | 114.8% | 74.5% |
| Book Value per Share | $25.01 | $26.96 | $26.46 | $25.91 | $26.45 |

The consolidated financial statements give retroactive effect to AEP's merger with CSW, which was accounted for as a pooling of interests, as if AEP and CSW had always been combined.
*Based on AEP historical dividend rate.

American Electric Power Company, Inc. (AEP) is one of the largest investor owned electric public utility holding companies in the U.S. serving over 4.8 million retail customers in eleven states (Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia) and selling bulk power at wholesale both within and beyond its domestic retail service area. AEP has 38,000 megawatts of generation and over 38,000 miles of transmission lines and 186,000 miles of distribution lines in the U.S. Subsidiaries own 1,250 megawatts as independent power producers in Colorado, Florida and Texas. In recent years AEP has expanded its domestic operations to include gas marketing, processing, storage and transportation operations, electric, gas and coal trading operations and telecommunication services and invested in and acquired foreign distribution operations in the U.K., Australia and Brazil and electricity generating facilities in China and Mexico. Subsidiaries also provide power engineering, generation and transmission plant maintenance and construction, and energy management services worldwide. AEP is one of the largest traders of electricity and gas in the U.S. In 2000 we established an energy trading operation in Europe.

Presently AEP is in the process of restructuring its assets and operations to separate the regulated operations from the non-regulated operations and to functionally and, where permitted by law, structurally unbundle its domestic vertically integrated electric utility business into separate generation, transmission and distribution businesses. The purpose of this restructuring is to focus our management and technical expertise to maximize the potential for growth of both non-regulated and regulated operations, to evaluate the performance of these separate and different businesses and to meet the separation requirements of federal and state restructuring legislation and codes of conduct. Five of AEP's 11 states (Arkansas, Ohio, Texas, Virginia, and West Virginia) are in various stages of transitioning to deregulation of generation and to customer choice and market-based pricing from monopoly and regulator set rates for the retail sale of electricity. When the transition is implemented in those states, transmission will be regulated by the Federal Energy Regulatory Commission and distribution services will continue to be cost-based rate regulated by the states. Although we are actively supporting the transition to competition, there is little progress in the remaining six states. Therefore, in the near term, our retail electric business in Indiana, Kentucky, Louisiana, Michigan, Oklahoma and Tennessee will continue to be operated as an integrated public utility subject to state regulation. The foreign energy delivery investments and operations are not cost-based rate regulated but they are generally subject to different forms of price controls, such as capped prices. As such these foreign investments and operations will be included in our unbundled regulated business.

On November 1, 2000, AEP filed a restructuring plan under PUHCA with the SEC seeking approval to form two wholly owned holding company subsidiaries of AEP to separately own AEP's regulated and non-regulated subsidiaries and to structurally separate into separate legal entities along functional lines (i.e. generation, transmission and distribution) six of the electric utility operating companies (APCo, CPL, CSPCo, OPCo, SWEPCo and WTU). These six operating companies do business in the states that are implementing restructuring (Arkansas, Ohio, Texas, Virginia and West Virginia). The remaining domestic electric operating companies will be functionally unbundled for internal management and internal reporting purposes and for financial segment reporting but will not be structurally unbundled into separate companies since state law and/or regulation prohibits such action. One holding company will hold the unbundled non-regulated electric generation subsidiaries and the non-regulated domestic and foreign subsidiaries including the European trading company and the foreign generating companies, while the other holding company will hold the bundled domestic regulated electric utility companies and the foreign distribution companies. The restructuring will facilitate management's strategy to grow the deregulated wholesale electricity supply and electric and gas trading business and to evaluate the other business operations to explore ways to improve their results of operations and to continuously evaluate and where necessary reshape our business to grow earnings and improve shareholder value. The legal transfer of assets and structural separation plans will also require FERC, certain state and other regulatory approvals.

2000 was a year of accomplishment that positions AEP for earnings growth. In 2000 we completed the merger of AEP and CSW, greatly increasing the scope and size of AEP; achieved the targeted merger savings; returned the two unit 2,110 MW Cook Plant to service after an extended outage; reached a settlement on a restructuring plan in Ohio that will allow our electric generating and supply business in Ohio to transition over five years to market pricing and recover its stranded cost, including generation-related regulatory assets; continued to grow our domestic electricity and gas trading businesses to become one of the largest electricity and gas traders; established and grew an energy trading operation in Europe; added to our gas assets and operations with the announcement in the first quarter of 2001 of the planned acquisition of Houston Pipe Line Company; restructured our incentive compensation plans to more closely align them with the creation of shareholder value; reduced our power plant operation and maintenance costs while increasing plant availability; established AEP Pro Serv, Inc. to market AEP's expertise in power engineering, environmental engineering and generating plant maintenance services worldwide; closed contracts to design, build, operate and market the output of new power plants for Dow Chemical, Buckeye Power and Columbia Energy; and initiated a re-design of our existing PeopleSoft financial software as part of an enterprise-wide application to fully integrate our financial, work management and supply chain software and to provide data on a business unit basis consistent with our corporate separation initiative.

Although 2000 was a year marked by significant accomplishments that position AEP for future earnings growth, it resulted in a reduction in earnings and earnings per share due mainly to non-recurring items, such as: a loss incurred from a court decision disallowing tax deductions for interest related to AEP's COLI program; the write-off of non-recoverable merger costs; the expensing of Cook nuclear restart costs in contrast to 1999 when a significant portion of the restart costs were deferred with regulatory approval; the write-off of certain extraordinary costs that were stranded and liabilities incurred in connection with the restructuring of the regulation of the electric utility business in Ohio, Virginia, and West Virginia to transition that portion of AEP's domestic electricity supply business from cost-based rate regulation to customer choice and market pricing; the recognition of losses associated with a CSW investment in Chile which was sold in the fourth quarter; an impairment writedown of AEP's investment in Yorkshire to reflect a pending sale of the investment in 2001; and write-offs of unrecoverable contract costs and goodwill on certain of CSW's non-regulated businesses acquired in the merger.

Earnings in 2001 are expected to improve significantly with the return of Cook Plant's 2,110 MW of generating capacity due to the completion of restart efforts and the cessation of significant restart costs at Cook and the growth of our wholesale marketing and trading business.

Our focus for 2001 will be on completing our corporate separation plan to separate our regulated and non-regulated businesses. We believe that a successful implementation of this plan will support our business objective of unlocking shareholder value by providing managers with a simpler structure through which business unit performance can be more easily anticipated and monitored thereby focusing management attention; permitting more efficient financing; and meeting the regulatory codes of conduct required as part of industry restructuring.

Although management expects that the future outlook for results of operations is excellent there are contingencies, challenges and obstacles to overcome and manage, such as new more stringent Federal EPA environmental requirements and recent complaints and related litigation, further delays in transition to competition supported in part by concerns that California's energy crisis could happen in our service territory, the recovery of generation-related regulatory assets and other stranded costs in Texas and any additional state jurisdictions that we can successfully promote the adoption of customer choice and a transition to market pricing from regulated rate setting, franchise fee litigation in Texas, litigation concerning AEP's financial disclosures regarding the extended Cook Plant safety outage and timing of the successful completion of restart efforts, the amortization of transition regulatory assets from the introduction of competition to our previously regulated domestic generation business and the amortization of deferred costs from the successful effort to restart Cook Plant and to merge AEP and CSW and the outcome of litigation to recover $90 million of duplicate tax expense from May 2001 to April 2002 resulting from restructuring in Ohio. These challenges, contingencies and obstacles, which are discussed in detail in the Notes to Consolidated Financial Statements and in Management's Discussion and Analysis of Financial Condition, Contingencies and Other Matters, are receiving management's full attention and we intend to work diligently to resolve these matters by finding workable solutions that balance the interests of our customers, our employees and our shareholders.

## Results of Operations

### Net Income

Although revenues increased by $1.3 billion net income declined to $267 million or $0.83 per share in 2000 from $972 million or $3.03 per share in 1999. The decrease was primarily due to Cook Nuclear Plant restart costs, a disallowance of tax deductions for corporate owned life insurance (COLI), expensing of costs related to AEP's recently completed merger with CSW, write offs related to non-regulated subsidiaries and an extraordinary loss from the discontinuance of regulatory accounting for generation in certain states. In 1999 net income was virtually unchanged as increased expenses to prepare the Cook Nuclear Plant for restart, net of related deferrals, were offset by a gain from a sale of a 50% interest in a cogeneration project.

### Revenues Increase

AEP's revenues include a significant number of transactions from the trading of electricity and gas. Revenues from trading of electricity are recorded net of purchases as domestic electric utility wholesale sales for transactions in AEP's traditional marketing area (up to two transmission systems from the AEP service territory) and as revenues from worldwide electric and gas operations for transactions beyond two transmission systems from AEP. Revenues from gas trading are recorded net of purchases and reported in revenues from worldwide electric and gas operations. Trading transactions involve the purchase and sale of substantial amounts of electricity and gas.

The level of electricity trading transactions tends to fluctuate due to the highly competitive nature of the short-term (spot) energy market and other factors, such as affiliated and unaffiliated generating plant availability, weather conditions and the economy. The FERC rules, which introduced a greater degree of competition into the wholesale energy market, have had a major effect on the volume of electricity trading as most electricity is traded in the short-term market.

AEP's total revenues increased 10% in 2000 and 5% in 1999. The table below shows the changes in the components of revenues from domestic electric utility operations and worldwide electric and gas operations. While worldwide electric and gas operations revenues increased 12% in 2000, most of the increase in total revenues was caused by the increased revenues from domestic electric utility operations.

| | Increase (Decrease) From Previous Year | | | |
|---|---|---|---|---|
| (Dollars in Millions) | 2000 | | 1999 | |
| | Amount | % | Amount | % |
| Domestic Electric Utility Operations: | | | | |
| Retail: | | | | |
| Residential | $ 230 | | $ 18 | |
| Commercial | 163 | | 56 | |
| Industrial | (71) | | 11 | |
| Other | 25 | | 7 | |
| | 347 | 4.2 | 92 | 1.1 |
| Wholesale | 672 | 59.9 | (145) | (11.5) |
| Other | (30) | (6.8) | 57 | 15.3 |
| Total Domestic Electric Utility Operations | 989 | 10.1 | 4 | - |
| Worldwide Electric and Gas Operations | 298 | 11.6 | 563 | 28.1 |
| Total | $1,287 | 10.4 | $ 567 | 4.8 |

The increase in total revenues from domestic electric utility operations in 2000 was primarily due to a 38% increase in wholesale sales volume and increased retail fuel revenues as a result of higher gas prices used to generate electricity. The reduction in industrial revenues in 2000 is attributable to the expiration of a long-term contract on December 31, 1999. The significant increase in wholesale sales volume, which accounted for a 60% increase in wholesale revenues, resulted from efforts to grow AEP's energy marketing and trading operations, favorable market conditions, and the availability of additional generation due to the return to service of one of the Cook Plant nuclear units in June 2000 and improved generating unit availability due mainly to improved outage management. The second Cook Plant unit which returned to service in December 2000 did not have a significant impact on revenues.

In 1999 revenues from domestic electric utility operations were unchanged. A 1% gain in retail revenues was more than offset by a 12% decline in wholesale revenues. The 12% decline in wholesale revenues in 1999 was predominantly due to a decrease in wholesale energy sales and a reduction in net revenues from power trading due to a decline in margins. The decrease in wholesale sales reflects the expiration in July 1998 of a power contract which supplied power to several municipal customers and the decision by another wholesale customer who buys energy under a unit power agreement not to take energy from AEP during an outage of that unit. The decline in wholesale margins in 1999 reflects the moderation of weather and the effected capacity shortages experienced in the summer of 1998.

Revenues from worldwide electric and gas operations increased 12% in 2000 due to increased natural gas and gas liquid product prices. Volumes of natural gas remained consistent with the prior year, however, prices increased significantly.

In 1999 revenues derived from worldwide electric and gas operations increased 28%. This increase is primarily due to the acquisitions in December 1998, of CitiPower in Australia and of LIG, and the commercial operation of a two-unit 250 MW coal-fired generating plant in China.

Operating Expenses Increase

Changes in the components of operating expenses were as follows:

| (Dollars in Millions) | 2000 Amount | 2000 % | 1999 Amount | 1999 % |
|---|---|---|---|---|
| | Increase (Decrease) From Previous Year | | | |
| Fuel and Purchased Power | $ 679 | 19.7 | $ (6) | (0.2) |
| Maintenance and Other Operation | 342 | 12.8 | 79 | 3.0 |
| Merger Costs | 203 | - | - | - |
| Depreciation and Amortization | 51 | 5.0 | 22 | 2.2 |
| Taxes Other Than Income Taxes | 7 | 1.1 | 5 | 0.8 |
| Worldwide Electric and Gas Operations | 304 | 13.3 | 422 | 22.7 |
| Total | $1,586 | 15.7 | $522 | 5.5 |

Fuel and purchased power expense increased 20% in 2000 due to a significant increase in the cost of natural gas used for generation. Natural gas usage for generation declined 5% while the cost of natural gas consumed rose 60%. Net income was not impacted by this significant cost increase due to the operation of fuel recovery mechanisms. These fuel recovery mechanisms generally provide for the deferral of fuel costs above the amounts included in rates or the accrual of revenues for fuel costs not yet recovered. Upon regulatory commission review and approval of the unrecovered fuel costs, the accrued or deferred amounts are billed to customers.

The increase in maintenance and other operation expense in 2000 was mainly due to increased expenditures to prepare the Cook Plant nuclear units for restart following an extended NRC monitored outage and increased usage of and prices for emissions allowances. The increase in Cook Plant restart costs resulted from the effect of deferring restart costs in 1999 and an increase in the restart expenditure level. The Cook Plant began an extended outage in September 1997 when both nuclear generating units were shut down because of questions regarding the operability of certain safety systems. In 1999 a portion of incremental restart expenses were deferred in accordance with IURC and MPSC settlement agreements which resolved all jurisdictional rate-related issues related to the Cook Plant's extended outage. Unit 2 returned to service in June and achieved full power operation on July 5, 2000 and Unit 1 returned to service in December and achieved full power operation on January 3, 2001. The increase in emission allowance usage and prices resulted from the stricter air quality standards of Phase II of the 1990 Clean Air Act Amendments, which became effective on January 1, 2000. The increase in maintenance and other operation expense in 1999 was primarily due to a NRC required 10-year inspection of STP Units 1 and 2 and increased expenditures to prepare the Cook Plant nuclear units for restart. Although a portion of Cook Plant restart costs were deferred in 1999 pursuant to regulatory orders, net expenditures charged to expense increased over 1998.

With the consummation of the merger with CSW, certain deferred merger costs were expensed. The merger costs charged to expense included transaction and transition costs not allocable to and recoverable from ratepayers under regulatory commission approved settlement agreements to share net merger savings.

Worldwide electric and gas operations expense in 2000 increased 13% to $2.6 billion from $2.3 billion. The increase was due to the increase in natural gas prices, the write down to market value of a CSW available-for-sale investment in a Chilean-based electric company sold in December 2000 and the effect of a gain in 1999 on the planned sale of a 50% interest in a cogeneration project. Federal law limits ownership in qualifying cogeneration facilities to 50%. CSW Energy constructed the project and completed the sale of a 50% interest in the project to an unaffiliated entity in 1999. Expenses of the worldwide electric and gas operations increased in 1999 due to the addition of expenses of businesses acquired in December 1998 and the start of commercial operation of the two-unit 250 MW coal-fired generating plant in China.

Interest and Preferred Dividends

In 2000 interest and preferred stock dividends increased by 16% to $1,160 million from $996 million in 1999 due to additional interest expense from the ruling on the litigation with the government disallowing COLI tax deductions and AEP's intention to maintain flexibility for corporate separation by issuing short-term debt at flexible rates. The use of fixed interest rate swaps has been employed to mitigate the risk from floating interest rates.

The 11% increase in interest and preferred stock dividends in 1999 was due primarily to increased interest expense on long-term debt. Long-term debt outstanding increased $564 million in 1999.

Other Income

Other income decreased from $139 million in 1999 to $33 million in 2000 primarily due to a write-down of AEP's Yorkshire investment to reflect a proposed sale in 2001, losses of non-regulated subsidiaries accounted for on an equity basis, and a charge for the discontinuance of an electric storage water heater demand side management program.

Other income increased 46% in 1999 primarily due to gains from the sale of investments at SEEBOARD and from interest income related to a cogeneration power plant.

Income Taxes

Income taxes increased in 2000 primarily due to an unfavorable ruling in AEP's suit against the government over interest deductions claimed relating to AEP's COLI program and nondeductible merger related costs.

## AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
### Consolidated Statements of Income
(in millions - except per share amounts)

| | Year Ended December 31, 2000 | 1999 | 1998 |
|---|---|---|---|
| REVENUES: | | | |
| Domestic Electric Utility Operations | $10,827 | $ 9,838 | $ 9,834 |
| Worldwide Electric and Gas Operations | 2,867 | 2,569 | 2,006 |
| TOTAL REVENUES | 13,694 | 12,407 | 11,840 |
| EXPENSES: | | | |
| Fuel and Purchased Power | 4,128 | 3,449 | 3,455 |
| Maintenance and Other Operation | 3,017 | 2,675 | 2,596 |
| Non-recoverable Merger Costs | 203 | - | - |
| Depreciation and Amortization | 1,062 | 1,011 | 989 |
| Taxes Other Than Income Taxes | 671 | 664 | 659 |
| Worldwide Electric and Gas Operations | 2,587 | 2,283 | 1,861 |
| TOTAL EXPENSES | 11,668 | 10,082 | 9,560 |
| OPERATING INCOME | 2,026 | 2,325 | 2,280 |
| OTHER INCOME (net) | 33 | 139 | 95 |
| INCOME BEFORE INTEREST, PREFERRED DIVIDENDS AND INCOME TAXES | 2,059 | 2,464 | 2,375 |
| INTEREST AND PREFERRED DIVIDENDS | 1,160 | 996 | 898 |
| INCOME BEFORE INCOME TAXES | 899 | 1,468 | 1,477 |
| INCOME TAXES | 597 | 482 | 502 |
| INCOME BEFORE EXTRAORDINARY ITEM | 302 | 986 | 975 |
| EXTRAORDINARY LOSSES: | | | |
| DISCONTINUANCE OF REGULATORY ACCOUNTING FOR GENERATION | (35) | (8) | - |
| LOSS ON REACQUIRED DEBT | - | (6) | - |
| NET INCOME | $ 267 | $ 972 | $ 975 |
| AVERAGE NUMBER OF SHARES OUTSTANDING | 322 | 321 | 318 |
| EARNINGS PER SHARE: | | | |
| Income Before Extraordinary Item | $ 0.94 | $3.07 | $3.06 |
| Extraordinary Losses | (0.11) | (.04) | - |
| Net Income | $ 0.83 | $3.03 | $3.06 |
| CASH DIVIDENDS PAID PER SHARE | $ 2.40 | $2.40 | $2.40 |

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

## AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
### Consolidated Balance Sheets
(in millions - except share data)

| ASSETS | December 31, 2000 | December 31, 1999 |
|---|---|---|
| CURRENT ASSETS: | | |
| Cash and Cash Equivalents | $ 437 | $ 609 |
| Special Deposits | - | 50 |
| Accounts Receivable: | | |
| Customers | 827 | 553 |
| Miscellaneous | 2,883 | 1,486 |
| Allowance for Uncollectible Accounts | (11) | (12) |
| Energy Trading Contracts | 16,627 | 1,001 |
| Other | 1,268 | 1,311 |
| TOTAL CURRENT ASSETS | 22,031 | 4,998 |
| PROPERTY PLANT AND EQUIPMENT: | | |
| Electric: | | |
| Production | 16,328 | 15,869 |
| Transmission | 5,609 | 5,495 |
| Distribution | 10,843 | 10,432 |
| Other (including gas and coal mining assets and nuclear fuel) | 4,077 | 4,081 |
| Construction Work in Progress | 1,231 | 1,061 |
| Total Property, Plant and Equipment | 38,088 | 36,938 |
| Accumulated Depreciation and Amortization | 15,695 | 15,073 |
| NET PROPERTY, PLANT AND EQUIPMENT | 22,393 | 21,865 |
| REGULATORY ASSETS | 3,698 | 3,464 |
| INVESTMENTS IN POWER AND COMMUNICATIONS PROJECTS | 782 | 862 |
| GOODWILL (NET OF AMORTIZATION) | 1,382 | 1,531 |
| LONG-TERM ENERGY TRADING CONTRACTS | 1,620 | 136 |
| OTHER ASSETS | 2,642 | 2,863 |
| TOTAL | $54,548 | $35,719 |

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

## AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
### Consolidated Balance Sheets

| | December 31, 2000 | December 31, 1999 |
|---|---|---|
| **LIABILITIES AND SHAREHOLDERS' EQUITY** | | |
| CURRENT LIABILITIES: | | |
| Accounts Payable | $ 2,627 | $ 1,280 |
| Short-term Debt | 4,333 | 3,012 |
| Long-term Debt Due Within One Year* | 1,152 | 1,367 |
| Energy Trading Contracts | 16,801 | 964 |
| Other | 2,154 | 1,443 |
| TOTAL CURRENT LIABILITIES | 27,067 | 8,066 |
| LONG-TERM DEBT* | 9,602 | 10,157 |
| CERTAIN SUBSIDIARY OBLIGATED, MANDATORILY REDEEMABLE, PREFERRED SECURITIES OF SUBSIDIARY TRUSTS HOLDING SOLELY JUNIOR SUBORDINATED DEBENTURES OF SUCH SUBSIDIARIES | 334 | 335 |
| DEFERRED INCOME TAXES | 4,875 | 5,150 |
| DEFERRED GAIN ON SALE AND LEASEBACK - ROCKPORT PLANT UNIT 2 | 203 | 213 |
| DEFERRED INVESTMENT TAX CREDITS | 528 | 580 |
| LONG-TERM ENERGY TRADING CONTRACTS | 1,381 | 108 |
| DEFERRED CREDITS AND REGULATORY LIABILITIES | 637 | 607 |
| OTHER NONCURRENT LIABILITIES | 1,706 | 1,648 |
| CUMULATIVE PREFERRED STOCK OF SUBSIDIARIES* | 161 | 182 |
| COMMITMENTS AND CONTINGENCIES (Note 8) | | |
| COMMON SHAREHOLDERS' EQUITY: | | |
| Common Stock-Par Value $6.50: (2000 / 1999) Shares Authorized. .600,000,000 / 600,000,000; Shares Issued. . . .331,019,146 / 330,692,317 (8,999,992 shares were held in treasury at December 31, 2000 and 1999) | 2,152 | 2,149 |
| Paid-in Capital | 2,915 | 2,898 |
| Accumulated Other Comprehensive Income (Loss) | (103) | (4) |
| Retained Earnings | 3,090 | 3,630 |
| TOTAL COMMON SHAREHOLDERS' EQUITY | 8,054 | 8,673 |
| TOTAL | $54,548 | $35,719 |

*See Accompanying Schedules.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
Consolidated Statements of Cash Flows
(in millions)

| | Year Ended December 31, 2000 | 1999 | 1998 |
|---|---|---|---|
| OPERATING ACTIVITIES: | | | |
| Net Income | $ 267 | $ 972 | $ 975 |
| Adjustments for Noncash Items: | | | |
| Depreciation and Amortization | 1,299 | 1,294 | 1,171 |
| Deferred Federal Income Taxes | (170) | 180 | (2) |
| Deferred Investment Tax Credits | (36) | (38) | (37) |
| Amortization (Deferral) of Operating Expenses and Carrying Charges (net) | 48 | (151) | 15 |
| Equity in Earnings of Yorkshire Electricity Group plc | (44) | (45) | (38) |
| Extraordinary Item | 35 | 14 | - |
| Deferred Costs Under Fuel Clause Mechanisms | (449) | (191) | 36 |
| Changes in Certain Current Assets and Liabilities: | | | |
| Accounts Receivable (net) | (1,632) | (80) | (329) |
| Fuel, Materials and Supplies | 147 | (162) | (23) |
| Accrued Utility Revenues | (79) | (35) | 5 |
| Accounts Payable | 1,322 | 74 | 270 |
| Taxes Accrued | 172 | 29 | 20 |
| Payment of Disputed Tax and Interest Related to COLI | 319 | (16) | (303) |
| Other (net) | 304 | (231) | 195 |
| Net Cash Flows From Operating Activities | 1,503 | 1,614 | 1,955 |
| INVESTING ACTIVITIES: | | | |
| Construction Expenditures | (1,773) | (1,680) | (1,396) |
| Investment in CitiPower | - | - | (1,054) |
| Investment in Gas Assets | - | - | (340) |
| Other | 19 | 7 | (54) |
| Net Cash Flows Used For Investing Activities | (1,754) | (1,673) | (2,844) |
| FINANCING ACTIVITIES: | | | |
| Issuance of Common Stock | 14 | 93 | 96 |
| Issuance of Long-term Debt | 1,124 | 1,391 | 2,645 |
| Retirement of Cumulative Preferred Stock | (20) | (170) | (28) |
| Retirement of Long-term Debt | (1,565) | (915) | (1,101) |
| Change in Short-term Debt (net) | 1,308 | 812 | 264 |
| Dividends Paid on Common Stock | (805) | (833) | (827) |
| Other Financing Activities | - | (43) | - |
| Net Cash Flows From Financing Activities | 56 | 335 | 1,049 |
| Effect of Exchange Rate Change on Cash | 23 | (2) | - |
| Net Increase (Decrease) in Cash and Cash Equivalents | (172) | 274 | 160 |
| Cash and Cash Equivalents January 1 | 609 | 335 | 175 |
| Cash and Cash Equivalents December 31 | $ 437 | $ 609 | $ 335 |

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

## AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
### Consolidated Statements of Common Shareholders' Equity

(in millions)

| | Common Shares | Stock Amount | Paid-In Capital | Retained Earnings | Accumulated Other Comprehensive Income (Loss) | Total |
|---|---|---|---|---|---|---|
| JANUARY 1, 1998 | 326 | $2,036 | $2,818 | $3,356 | $ 23 | $8,233 |
| Conforming Change in Accounting Policy | - | - | - | (13) | - | (13) |
| Reclassification Adjustment | - | 85 | (85) | - | - | - |
| Adjusted Balance at Beginning of Period | 326 | 2,121 | 2,733 | 3,343 | 23 | 8,220 |
| Issuances | 2 | 13 | 83 | - | - | 96 |
| Retirements and Other | - | - | 2 | 3 | - | 5 |
| Cash Dividends Declared | - | - | - | (827) | - | (827) |
| | | | | | | 7,494 |
| Comprehensive Income: | | | | | | |
| Other Comprehensive Income, Net of Taxes | | | | | | |
| Foreign Currency Translation Adjustment | - | - | - | - | 6 | 6 |
| Unrealized Loss on Securities | - | - | - | - | (14) | (14) |
| Adjustments for Gain Included in Net Income | - | - | - | - | (7) | (7) |
| Minimum Pension Liability | - | - | - | - | (1) | (1) |
| Net Income | - | - | - | 975 | - | 975 |
| Total Comprehensive Income | | | | | | 959 |
| DECEMBER 31, 1998 | 328 | 2,134 | 2,818 | 3,494 | 7 | 8,453 |
| Conforming Change in Accounting Policy | - | - | - | (1) | - | (1) |
| Adjusted Balance at Beginning of Period | 328 | 2,134 | 2,818 | 3,493 | 7 | 8,452 |
| Issuances | 3 | 15 | 77 | - | - | 92 |
| Retirements and Other | - | - | 3 | - | - | 3 |
| Cash Dividends Declared | - | - | - | (833) | - | (833) |
| | | | | | | 7,714 |
| Comprehensive Income: | | | | | | |
| Other Comprehensive Income, Net of Taxes | | | | | | |
| Foreign Currency Translation Adjustment | - | - | - | - | (13) | (13) |
| Minimum Pension Liability | - | - | - | - | 2 | 2 |
| Net Income | - | - | - | 972 | - | 972 |
| Total Comprehensive Income | | | | | | 961 |
| DECEMBER 31, 1999 | 331 | 2,149 | 2,898 | 3,632 | (4) | 8,675 |
| Conforming Change in Accounting Policy | - | - | - | (2) | - | (2) |
| Adjusted Balance at Beginning of Period | 331 | 2,149 | 2,898 | 3,630 | (4) | 8,673 |
| Issuances | - | 3 | 11 | - | - | 14 |
| Cash Dividends Declared | - | - | - | (805) | - | (805) |
| Other | - | - | 6 | (2) | - | 4 |
| | | | | | | 7,886 |
| Comprehensive Income: | | | | | | |
| Other Comprehensive Income, Net of Taxes | | | | | | |
| Foreign Currency Translation Adjustment | - | - | - | - | (119) | (119) |
| Reclassification Adjustment For Loss Included in Net Income | - | - | - | - | 20 | 20 |
| Net Income | - | - | - | 267 | - | 267 |
| Total Comprehensive Income | | | | | | 168 |
| DECEMBER 31, 2000 | 331 | $2,152 | $2,915 | $3,090 | $(103) | $8,054 |

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

## AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
## Schedule of Consolidated Cumulative Preferred Stocks of Subsidiaries

| | December 31, 2000 | | | |
|---|---|---|---|---|
| | Call Price per Share (a) | Shares Authorized(b) | Shares Outstanding(g) | Amount (In Millions) |
| Not Subject to Mandatory Redemption: | | | | |
| 4.00% - 5.00% | $102-$110 | 1,525,903 | 614,608 | $ 61 |
| Subject to Mandatory Redemption: | | | | |
| 5.90% - 5.92% (c) | (d) | 1,950,000 | 333,100 | $ 33 |
| 6.02% - 6-7/8% (c) | (e) | 1,650,000 | 513,450 | 52 |
| 7% (f) | (f) | 250,000 | 150,000 | 15 |
| Total Subject to Mandatory Redemption (c) | | | | $100 |

| | December 31, 1999 | | | |
|---|---|---|---|---|
| | Call Price per Share (a) | Shares Authorized(b) | Shares Outstanding(g) | Amount (In Millions) |
| Not Subject to Mandatory Redemption: | | | | |
| 4.00% - 5.00% | $102-$110 | 1,525,903 | 629,671 | $ 63 |
| Subject to Mandatory Redemption: | | | | |
| 5.90% - 5.92% (c) | (d) | 1,950,000 | 343,100 | $ 34 |
| 6.02% - 6-7/8% (c) | (e) | 1,950,000 | 597,950 | 60 |
| 7% (f) | (f) | 250,000 | 250,000 | 25 |
| Total Subject to Mandatory Redemption (c) | | | | $119 |

NOTES TO SCHEDULE OF CUMULATIVE PREFERRED STOCKS OF SUBSIDIARIES

(a) At the option of the subsidiary the shares may be redeemed at the call price plus accrued dividends. The involuntary liquidation preference is $100 per share for all outstanding shares.

(b) As of December 31, 2000 the subsidiaries had 13,592,750, 22,200,000 and 7,713,495 shares of $100, $25 and no par value preferred stock, respectively, that were authorized but unissued.

(c) Shares outstanding and related amounts are stated net of applicable retirements through sinking funds(generally at par) and reacquisitions of shares in anticipation of future requirements. The subsidiaries reacquired enough shares in 1997 to meet all sinking fund requirements on certain series until 2008 and on certain series until 2009 when all remaining outstanding shares must be redeemed. The sinking fund provisions of the series subject to mandatory redemption aggregate (after deducting sinking fund requirements) of $5 million in 2002, $12 million in 2003, $12 million in 2004 and $2 million in 2005.

(d) Not callable prior to 2003; after that the call price is $100 per share.

(e) Not callable prior to 2000; after that the call price is $100 per share.

(f) With sinking fund.

(g) The number of shares of preferred stock redeemed is 209,563 shares in 2000, 1,698,276 shares in 1999 and 281,250 shares in 1998.

## AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
### Schedule of Consolidated Long-term Debt of Subsidiaries

| Maturity | Weighted Average Interest Rate December 31, 2000 | Interest Rates at December 31, 2000 | 1999 | December 31, 2000 (in millions) | 1999 |
|---|---|---|---|---|---|
| FIRST MORTGAGE BONDS | | | | | |
| 2000-2003 | 6.96% | 5.91%-8.95% | 5.25%-8.95% | $ 1,247 | $ 1,621 |
| 2004-2008 | 6.97% | 6-1/8%-8% | 6-1/8%-8% | 1,140 | 1,148 |
| 2020-2025 | 7.74% | 6-7/8%-8.80% | 6-7/8%-8.80% | 1,104 | 1,172 |
| INSTALLMENT PURCHASE CONTRACTS (a) | | | | | |
| 2000-2009 | 5.53% | 4.90%-7.70% | 4.80%-7.70% | 234 | 235 |
| 2011-2030 | 6.02% | 4.875%-8.20% | 3.332%-8.20% | 1,447 | 1,477 |
| NOTES PAYABLE (b) | | | | | |
| 2000-2021 | 7.14% | 6.20%-9.60% | 5.8675%-9.60% | 1,181 | 2,030 |
| SENIOR UNSECURED NOTES | | | | | |
| 2000-2004 | 6.99% | 6.50%-7.45% | 6.07%-7.45% | 2,049 | 1,403 |
| 2005-2009 | 6.59% | 6.24%-6.91% | 6.24%-6.91% | 475 | 488 |
| 2038 | 7.30% | 7.20%-7-3/8% | 7.20%-7-3/8% | 340 | 340 |
| JUNIOR DEBENTURES | | | | | |
| 2025-2038 | 8.05% | 7.60%-8.72% | 7.60%-8.72% | 620 | 620 |
| YANKEE BONDS AND EURO BONDS | | | | | |
| 2001-2006 | 8.51% | 7.98%-8.875% | 7.98%-8.875% | 684 | 742 |
| OTHER LONG-TERM DEBT (c) | | | | 280 | 300 |
| Unamortized Discount (net) | | | | (47) | (52) |
| Total Long-term Debt Outstanding (d) | | | | 10,754 | 11,524 |
| Less Portion Due Within One Year | | | | 1,152 | 1,367 |
| Long-term Portion | | | | $ 9,602 | $10,157 |

NOTES TO SCHEDULE OF CONSOLIDATED LONG-TERM DEBT OF SUBSIDIARIES

(a) For certain series of installment purchase contracts interest rates are subject to periodic adjustment. Certain series will be purchased on demand at periodic interest-adjustment dates. Letters of credit from banks and standby bond purchase agreements support certain series.
(b) Notes payable represent outstanding promissory notes issued under term loan agreements and revolving 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.
(c) Other long-term debt consists of a liability along with accrued interest for disposal of spent nuclear fuel (see Note 8 of the Notes to Consolidated Financial Statements) and financing obligation under sale lease back agreements.
(d) Long-term debt outstanding at December 31, 2000 is payable as follows:

| | Principal Amount (in millions) |
|---|---|
| 2001 | $ 1,152 |
| 2002 | 1,167 |
| 2003 | 1,628 |
| 2004 | 884 |
| 2005 | 616 |
| Later Years | 5,354 |
| Total Principal Amount | 10,801 |
| Unamortized Discount | (47) |
| Total | $10,754 |

AMERICAN ELECTRIC POWER COMPANY INC. AND SUBSIDIARY COMPANIES

Index to Notes to Consolidated Financial Statements

The notes listed below are combined with the notes to financial statements for AEP and its other subsidiary registrants. The combined footnotes begin on page L-1.


| | Combined Footnote Reference |
|---|---|
| Significant Accounting Policies | Note 1 |
| Extraordinary Items | Note 2 |
| Merger | Note 3 |
| Nuclear Plant Restart | Note 4 |
| Rate Matters | Note 5 |
| Effects of Regulation | Note 6 |
| Industry Restructuring | Note 7 |
| Commitments and Contingencies | Note 8 |
| Acquisitions | Note 9 |
| International Investments | Note 10 |
| Staff Reductions | Note 11 |
| Benefit Plans | Note 12 |
| Stock-Based Compensation | Note 13 |
| Business Segments | Note 14 |
| Financial Instruments, Credit and Risk Management | Note 15 |
| Income Taxes | Note 16 |
| Supplementary Information | Note 17 |
| Leases | Note 18 |
| Lines of Credit and Factoring of Receivables | Note 19 |
| Unaudited Quarterly Financial Information | Note 20 |
| Trust Preferred Securities | Note 21 |

## MANAGEMENT'S RESPONSIBILITY

The management of American Electric Power Company, Inc. is responsible for the integrity and objectivity of the information and representations in this annual report, including the consolidated financial statements. These statements have been prepared in conformity with generally accepted accounting principles, using informed estimates where appropriate, to reflect the Company's financial condition and results of operations. The information in other sections of the annual report is consistent with these statements.

The Company's Board of Directors has oversight responsibilities for determining that management has fulfilled its obligation in the preparation of the financial statements and in the ongoing examination of the Company's established internal control structure over financial reporting. The Audit Committee, which consists solely of outside directors and which reports directly to the Board of Directors, meets regularly with management, Deloitte & Touche LLP - independent auditors and the Company's internal audit staff to discuss accounting, auditing and reporting matters. To ensure auditor independence, both Deloitte & Touche LLP and the internal audit staff have unrestricted access to the Audit Committee.

The financial statements have been audited by Deloitte & Touche LLP, whose report appears on the next page. The auditors provide an objective, independent review as to management's discharge of its responsibilities insofar as they relate to the fairness of the Company's reported financial condition and results of operations. Their audit includes procedures believed by them to provide reasonable assurance that the financial statements are free of material misstatement and includes an evaluation of the Company's internal control structure over financial reporting.

## INDEPENDENT AUDITORS' REPORT

To the Shareholders and Board of Directors
of American Electric Power Company, Inc.:

We have audited the consolidated balance sheets of American Electric Power Company, Inc. and its subsidiaries as of December 31, 2000 and 1999, and the related consolidated statements of income, comprehensive income, common shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2000. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements based on our audits. The consolidated financial statements give retroactive effect to the merger of American Electric Power Company, Inc. and its subsidiaries and Central and South West Corporation and its subsidiaries, which has been accounted for as a pooling of interests as described in Note 3 to the consolidated financial statements. We did not audit the consolidated balance sheet of Central and South West Corporation and its subsidiaries as of December 31, 1999, or the related consolidated statements of income, comprehensive income, common shareholders' equity, and cash flows for the years ended December 31, 1999 and 1998, which statements reflect total assets of $14,162,000,000 as of December 31, 1999, and total revenues of $5,537,000,000 and $5,482,000,000 for the years ended December 31, 1999 and 1998, respectively. Those consolidated statements, before the restatement described in Note 3, were audited by other auditors whose report, dated February 25, 2000, has been furnished to us, and our opinion, insofar as it relates to those amounts included for Central and South West Corporation and its subsidiaries for 1999 and 1998, is based solely on the report of such other auditors.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes 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 and the report of the other auditors provide a reasonable basis for our opinion.

In our opinion, based on our audits and the report of the other auditors, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of American Electric Power Company, Inc. and its subsidiaries as of December 31, 2000 and 1999, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2000 in conformity with accounting principles generally accepted in the United States of America.

We also audited the adjustments described in Note 3 that were applied to restate the 1999 and 1998 financial statements to give retroactive effect to the change in the method of accounting for vacation pay accruals. In our opinion, such adjustments are appropriate and have been properly applied.

Deloitte & Touche LLP
Columbus, Ohio
February 26, 2001

# INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES

-This page intentionally left blank.-

## INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
Selected Consolidated Financial Data

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2000 | 1999 | 1998 (in thousands) | 1997 | 1996 |
| INCOME STATEMENTS DATA: | | | | | |
| Operating Revenues | $1,548,476 | $1,394,119 | $1,405,794 | $1,339,232 | $1,328,493 |
| Operating Expenses | 1,583,178 | 1,285,467 | 1,239,787 | 1,131,444 | 1,108,076 |
| Operating Income (Loss) | (34,702) | 108,652 | 166,007 | 207,788 | 220,417 |
| Nonoperating Income (Loss) | 9,933 | 4,530 | (839) | 4,415 | 2,729 |
| Income (Loss) Before Interest Charges | (24,769) | 113,182 | 165,168 | 212,203 | 223,146 |
| Interest Charges | 107,263 | 80,406 | 68,540 | 65,463 | 65,993 |
| Net Income (Loss) | (132,032) | 32,776 | 96,628 | 146,740 | 157,153 |
| Preferred Stock Dividend Requirements | 4,624 | 4,885 | 4,824 | 5,736 | 10,681 |
| Earnings (Loss) Applicable to Common Stock | $ (136,656) | $ 27,891 | $ 91,804 | $ 141,004 | $ 146,472 |

| | December 31, | | | | |
|---|---|---|---|---|---|
| | 2000 | 1999 | 1998 (in thousands) | 1997 | 1996 |
| BALANCE SHEETS DATA: | | | | | |
| Electric Utility Plant | $4,871,473 | $4,770,027 | $4,631,848 | $4,514,497 | $4,377,669 |
| Accumulated Depreciation and Amortization | 2,280,521 | 2,194,397 | 2,081,355 | 1,973,937 | 1,861,893 |
| Net Electric Utility Plant | $2,590,952 | $2,575,630 | $2,550,493 | $2,540,560 | $2,515,776 |
| Total Assets | $5,818,547 | $4,576,696 | $4,148,523 | $3,967,798 | $3,897,484 |
| Common Stock and Paid-in Capital | $ 789,656 | $ 789,323 | $ 789,189 | $ 789,056 | $ 787,856 |
| Retained Earnings | 3,443 | 166,389 | 253,154 | 278,814 | 269,071 |
| Total Common Shareholder's Equity | $ 793,099 | $ 955,712 | $1,042,343 | $1,067,870 | $1,056,927 |
| Cumulative Preferred Stock: | | | | | |
| Not Subject to Mandatory Redemption | $ 8,736 | $ 9,248 | $ 9,273 | $ 9,435 | $ 21,977 |
| Subject to Mandatory Redemption (a) | 64,945 | 64,945 | 68,445 | 68,445 | 135,000 |
| Total Cumulative Preferred Stock | $ 73,681 | $ 74,193 | $ 77,718 | $ 77,880 | $ 156,977 |
| Long-term Debt (a) | $1,388,939 | $1,324,326 | $1,175,789 | $1,049,237 | $1,042,104 |
| Obligations Under Capital Leases (a) | $ 163,173 | $ 187,965 | $ 186,427 | $ 195,227 | $ 130,965 |
| Total Capitalization and Liabilities | $5,818,547 | $4,576,696 | $4,148,523 | $3,967,798 | $3,897,484 |

---

*(a) Including portion due within one year.*

I&M is a public utility engaged in the generation, purchase, sale, transmission and distribution of electric power to 565,000 retail customers in its service territory in northern and eastern Indiana and a portion of southwestern Michigan. As a member of the AEP Power Pool, I&M shares the revenues and the costs of the AEP Power Pool's wholesale sales to neighboring utilities and power marketers. I&M also sells wholesale power to municipalities and electric cooperatives.

The cost of the AEP System's generating capacity is allocated among the AEP Power Pool members based on their relative peak demands and generating reserves through the payment of capacity charges or the receipt of capacity credits. AEP Power Pool members are also compensated for the out-of-pocket costs of energy delivered to the AEP Power Pool and charged for energy received from the AEP Power Pool.

The AEP Power Pool calculates each company's prior twelve month peak demand relative to the total peak demand of all member companies as a basis for sharing revenues and costs. The result of this calculation is each company's member load ratio (MLR) which determines each company's percentage share of revenues or costs. I&M as a member of the AEP Power Pool shares in the revenues and costs of the AEP Power Pool's wholesale sales to and net forward trades with other utility systems and power marketers. Revenues from forward electricity trades in AEP's traditional marketing area (up to two transmission systems from the AEP service territory) are recorded net of purchases as operating revenues and as nonoperating income for trades beyond two transmission systems from AEP. The AEP Power Pool also enters into power trading transactions for options, futures and swaps. I&M's share of these transactions is recorded in nonoperating income.

I&M is committed under unit power agreements to purchase all of 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. A long-term unit power agreement with an unaffiliated utility expired at the end of 1999 for the sale of 455 MW of AEGCo's Rockport Plant capacity. An agreement between AEGCo and KPCo provides for the sale of 390 MW of AEGCo's Rockport Plant capacity to KPCo through 2004. Therefore, effective January 1, 2000, I&M began purchasing 910 MW of AEGCo's 50% share of Rockport Plant capacity.

## Results of Operations

During 2000 both of the Cook Plant nuclear units were successfully restarted after being shutdown in September 1997 due to questions regarding the operability of certain safety systems which arose during a NRC architect engineer design inspection. See discussion in Note 4 of the Notes to Consolidated Financial Statements.

In February 2001 the U.S. District Court for the Southern District of Ohio ruled against AEP and certain of its subsidiaries, including I&M, in a suit over deductibility of interest claimed in AEP's consolidated tax return related to a corporate owned life insurance (COLI) program. In 1998 and 1999 I&M paid the disputed taxes and interest attributable to the COLI interest deductions for the taxable years 1991-98. The payments were included in Other Property and Investments pending the resolution of this matter. As a result of the Court's decision, I&M's net income was reduced by $66 million in 2000.

As a result of the costs incurred in 2000 to restart the Cook Plant nuclear units and the disallowance of COLI interest deductions, net income declined $165 million in 2000. In 1999 net income declined $64 million due primarily to the cost of efforts to restart the Cook Plant units.

## Operating Revenues

Operating revenues increased 11% in 2000 and decreased 1% in 1999. The increase in operating revenues in 2000 was primarily due to increased wholesale sales to the AEP Power Pool. The decrease in 1999 was primarily due to a decline in margins on wholesale sales and net power trading transactions within the AEP Power Pool's traditional marketing area. The following analyzes the changes in operating revenues:

| (dollars in millions) | Increase (Decrease) From Previous Year | | | |
|---|---|---|---|---|
| | 2000 | | 1999 | |
| | Amount | % | Amount | % |
| Retail: | | | | |
| Residential | $(37.3) | | $ 3.4 | |
| Commercial | (16.2) | | 0.7 | |
| Industrial | (30.0) | | (5.7) | |
| Other | (5.0) | | (0.2) | |
| | (88.5) | (9) | (1.8) | - |
| Wholesale | 253.7 | 84 | (18.2) | (6) |
| Transmission and Other | (10.8) | (21) | 8.3 | 20 |
| Total | $154.4 | 11 | $(11.7) | (1) |

The increase in operating revenues in 2000 is primarily due to increased wholesale sales to the AEP Power Pool. With the return to service of the Cook Plant units and purchasing more power from AEGCo due to the expiration of AEGCo's contract to sell power to an unaffiliated entity, I&M had more electricity available to sell to the AEP Power Pool. A decline in retail sales and retail price which led to a decrease in retail operating revenues partly offset the increase in wholesale revenues.

Operating revenues decreased slightly in 1999 primarily due to reduced margins on I&M's MLR share of wholesale sales and net revenues from regulated power trading transactions in the AEP Power Pool's traditional marketing area. The decline in margins reflects the moderation in 1999 of extreme weather in 1998 and capacity shortages experienced in the summer of 1998.

## Operating Expenses Increase

Total operating expenses increased 23% in 2000 and 4% in 1999 primarily due to costs related to the extended Cook Plant outage and efforts to restart the Cook Plant units. Also contributing to the increase in operating expenses in 2000 was the unfavorable COLI tax ruling and the additional purchases of power due to the expiration of an AEGCo unit power agreement to sell part of its Rockport Plant generation to an unaffiliated utility. The changes in the components of operating expenses were:

| (dollars in millions) | Increase (Decrease) From Previous Year | | | |
|---|---|---|---|---|
| | 2000 | | 1999 | |
| | Amount | % | Amount | % |
| Fuel | $ 25.5 | 14 | $ 12.8 | 7 |
| Purchased Power | 60.4 | 22 | (21.1) | (7) |
| Other Operation | 137.5 | 30 | 114.3 | 33 |
| Maintenance | 84.5 | 62 | (22.3) | (14) |
| Depreciation and Amortization | 4.9 | 3 | 4.9 | 3 |
| Taxes Other Than Federal Income Taxes | 11.0 | 19 | (8.8) | (13) |
| Federal Income Taxes | (26.1) | (149) | (34.1) | (66) |
| Total | $297.7 | 23 | $ 45.7 | 4 |

The increase in fuel expense in 2000 reflects an increase in nuclear generation as the Cook Plant units returned to service following an extended outage. Fuel expense increased in 1999 primarily due to an increase in coal-fired generation replacing power purchases from the AEP Power Pool.

Purchased power expense increased in 2000 due to increased purchases from AEGCo. As a result of the expiration of AEGCo's power sale contract with an unaffiliated utility on December 31, 1999, I&M was obligated to buy more of AEGCo's share of Rockport Plant power. The decrease in purchased power expense in 1999 reflects the purchase of less power in 1999 at lower prices from the AEP Power Pool, AEGCo and unaffiliated entities.

The increases in other operation expense in 2000 and 1999 were primarily due to expenditures to prepare the Cook Plant nuclear units for restart.

Maintenance expense increased in 2000 primarily due to expenditures to prepare the Cook Plant units for restart. The decline in maintenance expense in 1999 was due to cost containment efforts including staff reductions at I&M's fossil-fired power plants, in the engineering and maintenance staff of AEP Service Corporation and in I&M's transmission and distribution operations.

In 1999 the IURC and MPSC approved settlement agreements which allowed the deferral of $200 million of Cook Plant restart costs in 1999 for amortization over five years from 1999 through 2003. As a result, other operation and maintenance expense in 1999 reflected a net deferral of $160 million. See discussion in Note 4 of the Notes to Consolidated Financial Statements.

The increase in taxes other than federal income tax in 2000 is primarily attributable to an increase in Indiana supplemental net income tax reflecting the COLI decision related interest deduction disallowance and a favorable accrual adjustment recorded in December 1999 related to the filing of the 1998 tax return. The decrease in taxes other than federal income taxes in 1999 was primarily due to a decline in estimated taxable income for Indiana supplemental income tax.

Federal income taxes attributable to operations decreased in 2000 and 1999 due to decreases in pre-tax operating income. In 2000 the decrease was partially offset by an increase in tax expense related to the unfavorable ruling in the suit against the IRS over interest deductions claimed for the COLI program.

Nonoperating Income

The increase in nonoperating income in 2000 and 1999 is primarily due to the effect of net gains on non-regulated electricity trading transactions. The AEP Power Pool enters into non-regulated transactions for the purchase and sale of electricity options, futures and swaps, and for the forward purchase and sale of electricity outside of the AEP System's traditional marketing area. I&M's share of the AEP Power Pool's non-regulated trading transactions are included in nonoperating income.

Interest Charges

Interest charges increased in 2000 and 1999 due to increased borrowings to support expenditures for the Cook Plant restart effort and in 2000 also due to the recognition of deferred interest payments to the IRS on the disputed taxes.

# INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
## Consolidated Statements of Income

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2000 | 1999 | 1998 |
| | | (in thousands) | |
| OPERATING REVENUES | $1,548,476 | $1,394,119 | $1,405,794 |
| OPERATING EXPENSES: | | | |
| Fuel | 210,870 | 185,419 | 172,592 |
| Purchased Power | 337,376 | 276,962 | 298,046 |
| Other Operation | 599,012 | 461,494 | 347,207 |
| Maintenance | 219,854 | 135,331 | 157,593 |
| Depreciation and Amortization | 154,920 | 149,988 | 145,112 |
| Taxes Other Than Federal Income Taxes | 69,761 | 58,713 | 67,592 |
| Federal Income Tax Expense (Credit) | (8,615) | 17,560 | 51,645 |
| Total Operating Expenses | 1,583,178 | 1,285,467 | 1,239,787 |
| OPERATING INCOME (LOSS) | (34,702) | 108,652 | 166,007 |
| NONOPERATING INCOME (LOSS) | 9,933 | 4,530 | (839) |
| INCOME (LOSS) BEFORE INTEREST CHARGES | (24,769) | 113,182 | 165,168 |
| INTEREST CHARGES | 107,263 | 80,406 | 68,540 |
| NET INCOME (LOSS) | (132,032) | 32,776 | 96,628 |
| PREFERRED STOCK DIVIDEND REQUIREMENTS | 4,624 | 4,885 | 4,824 |
| EARNINGS (LOSS) APPLICABLE TO COMMON STOCK | $ (136,656) | $ 27,891 | $ 91,804 |

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

# INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
## Consolidated Balance Sheets

| ASSETS | December 31, 2000 | December 31, 1999 |
|---|---|---|
| | (in thousands) | |
| **ELECTRIC UTILITY PLANT:** | | |
| Production | $2,708,436 | $2,587,288 |
| Transmission | 945,709 | 928,758 |
| Distribution | 863,736 | 818,697 |
| General (including nuclear fuel) | 257,152 | 244,981 |
| Construction Work in Progress | 96,440 | 190,303 |
| Total Electric Utility Plant | 4,871,473 | 4,770,027 |
| Accumulated Depreciation and Amortization | 2,280,521 | 2,194,397 |
| NET ELECTRIC UTILITY PLANT | 2,590,952 | 2,575,630 |
| NUCLEAR DECOMMISSIONING AND SPENT NUCLEAR FUEL DISPOSAL TRUST FUNDS | 778,720 | 707,967 |
| LONG-TERM ENERGY TRADING CONTRACTS | 194,947 | 23,131 |
| OTHER PROPERTY AND INVESTMENTS | 131,417 | 190,527 |
| **CURRENT ASSETS:** | | |
| Cash and Cash Equivalents | 14,835 | 3,863 |
| Accounts Receivable: | | |
| Customers | 106,832 | 91,268 |
| Affiliated Companies | 48,706 | 48,901 |
| Miscellaneous | 27,491 | 18,644 |
| Allowance for Uncollectible Accounts | (759) | (1,848) |
| Fuel - at average cost | 16,532 | 27,597 |
| Materials and Supplies - at average cost | 84,471 | 84,149 |
| Accrued Utility Revenues | - | 44,428 |
| Energy Trading Contracts | 1,229,683 | 97,946 |
| Prepayments | 6,424 | 7,631 |
| TOTAL CURRENT ASSETS | 1,534,215 | 422,579 |
| REGULATORY ASSETS | 552,140 | 624,810 |
| DEFERRED CHARGES | 36,156 | 32,052 |
| TOTAL | $5,818,547 | $4,576,696 |

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

| | December 31, 2000 | December 31, 1999 |
|---|---|---|
| | (in thousands) | |
| **CAPITALIZATION AND LIABILITIES** | | |
| **CAPITALIZATION:** | | |
| Common Stock - No Par Value: | | |
| Authorized - 2,500,000 Shares | | |
| Outstanding - 1,400,000 Shares | $ 56,584 | $ 56,584 |
| Paid-in Capital | 733,072 | 732,739 |
| Retained Earnings | 3,443 | 166,389 |
| Total Common Shareholder's Equity | 793,099 | 955,712 |
| Cumulative Preferred Stock: | | |
| Not Subject to Mandatory Redemption | 8,736 | 9,248 |
| Subject to Mandatory Redemption | 64,945 | 64,945 |
| Long-term Debt | 1,298,939 | 1,126,326 |
| TOTAL CAPITALIZATION | 2,165,719 | 2,156,231 |
| **OTHER NONCURRENT LIABILITIES:** | | |
| Nuclear Decommissioning | 560,628 | 501,185 |
| Other | 108,600 | 242,522 |
| TOTAL OTHER NONCURRENT LIABILITIES | 669,228 | 743,707 |
| **CURRENT LIABILITIES:** | | |
| Long-term Debt Due Within One Year | 90,000 | 198,000 |
| Short-term Debt | - | 224,262 |
| Advances from Affiliates | 253,582 | - |
| Accounts Payable - General | 119,472 | 78,784 |
| Accounts Payable - Affiliated Companies | 75,486 | 31,118 |
| Taxes Accrued | 68,416 | 48,970 |
| Interest Accrued | 21,639 | 13,955 |
| Obligations Under Capital Leases | 100,848 | 11,072 |
| Energy Trading Contracts | 1,275,097 | 95,564 |
| Other | 97,070 | 91,684 |
| TOTAL CURRENT LIABILITIES | 2,101,610 | 793,409 |
| DEFERRED INCOME TAXES | 487,945 | 622,157 |
| DEFERRED INVESTMENT TAX CREDITS | 113,773 | 121,627 |
| DEFERRED GAIN ON SALE AND LEASEBACK - ROCKPORT PLANT UNIT 2 | 81,299 | 85,005 |
| LONG-TERM ENERGY TRADING CONTRACTS | 156,736 | 17,887 |
| DEFERRED CREDITS | 42,237 | 36,673 |
| COMMITMENTS AND CONTINGENCIES (Note 8) | | |
| TOTAL | $5,818,547 | $4,576,696 |

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

## INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
### Consolidated Statements of Cash Flows

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2000 | 1999 | 1998 |
| | | (in thousands) | |
| OPERATING ACTIVITIES: | | | |
| Net Income (Loss) | $(132,032) | $ 32,776 | $ 96,628 |
| Adjustments for Noncash Items: | | | |
| Depreciation and Amortization | 163,391 | 153,921 | 149,209 |
| Amortization of Incremental Nuclear Refueling Outage Expenses (net) | 5,737 | 8,480 | 14,142 |
| Amortization (Deferral) of Nuclear Outage Costs (net) | 40,000 | (160,000) | - |
| Deferred Federal Income Taxes | (125,179) | 85,727 | 17,905 |
| Deferred Investment Tax Credits | (7,854) | (8,152) | (8,266) |
| Unrecovered Fuel and Purchased Power Costs | 37,501 | (84,696) | (46,846) |
| Changes in Certain Current Assets and Liabilities: | | | |
| Accounts Receivable (net) | (25,305) | (19,178) | 1,462 |
| Fuel, Materials and Supplies | 10,743 | (12,880) | (2,983) |
| Accrued Utility Revenues | 44,428 | (7,151) | (6,756) |
| Accounts Payable | 85,056 | 19,068 | 22,440 |
| Taxes Accrued | 19,446 | 13,809 | (11,689) |
| Disputed Tax and Interest Related to COLI | 56,856 | (3,228) | (53,628) |
| Other (net) | (41,900) | 12,831 | (8,176) |
| Net Cash Flows From Operating Activities | 130,888 | 31,327 | 163,442 |
| INVESTING ACTIVITIES: | | | |
| Construction Expenditures | (171,071) | (165,331) | (147,627) |
| Proceeds from Sales of Property and Other | 587 | 2,501 | 4,419 |
| Net Cash Flows Used For Investing Activities | (170,484) | (162,830) | (143,208) |
| FINANCING ACTIVITIES: | | | |
| Issuance of Long-term Debt | 199,220 | 247,989 | 170,675 |
| Retirement of Cumulative Preferred Stock | (314) | (3,597) | (120) |
| Retirement of Long-term Debt | (148,000) | (109,500) | (55,000) |
| Changes in Advances from Affiliates (net) | 253,582 | - | - |
| Change in Short-term Debt (net) | (224,262) | 115,562 | (10,900) |
| Dividends Paid on Common Stock | (26,290) | (114,656) | (117,464) |
| Dividends Paid on Cumulative Preferred Stock | (3,368) | (5,856) | (4,734) |
| Net Cash Flows From (Used For) Financing Activities | 50,568 | 129,942 | (17,543) |
| Net Increase (Decrease) in Cash and Cash Equivalents | 10,972 | (1,561) | 2,691 |
| Cash and Cash Equivalents January 1 | 3,863 | 5,424 | 2,733 |
| Cash and Cash Equivalents December 31 | $ 14,835 | $ 3,863 | $ 5,424 |

Supplemental Disclosure:
Cash paid (received) for interest net of capitalized amounts was $82,511,000, $78,703,000 and $66,313,000 and for income taxes was $73,254,000, $(71,395,000) and $36,413,000 in 2000, 1999 and 1998, respectively. Noncash acquisitions under capital leases were $22,218,000, $10,852,000 and $9,658,000 in 2000, 1999 and 1998, respectively.

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

# INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
## Consolidated Statements of Retained Earnings

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2000 | 1999 | 1998 |
| | | (in thousands) | |
| Retained Earnings January 1 | $ 166,389 | $253,154 | $278,814 |
| Net Income (Loss) | (132,032) | 32,776 | 96,628 |
| | 34,357 | 285,930 | 375,442 |
| Deductions: | | | |
| Cash Dividends Declared: | | | |
| Common Stock | 26,290 | 114,656 | 117,464 |
| Cumulative Preferred Stock: | | | |
| 4-1/8% Series | 230 | 244 | 247 |
| 4.56% Series | 66 | 66 | 67 |
| 4.12% Series | 74 | 78 | 79 |
| 5.90% Series | 897 | 963 | 985 |
| 6-1/4% Series | 1,203 | 1,250 | 1,266 |
| 6.30% Series | 834 | 834 | 834 |
| 6-7/8% Series | 1,186 | 1,238 | 1,255 |
| Total Cash Dividends Declared | 30,780 | 119,329 | 122,197 |
| Capital Stock Expense | 134 | 212 | 91 |
| Total Deductions | 30,914 | 119,541 | 122,288 |
| Retained Earnings December 31 | $ 3,443 | $166,389 | $253,154 |

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

# INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
## Consolidated Statements of Capitalization

| | | | | | | December 31, 2000 | December 31, 1999 |
|---|---|---|---|---|---|---|---|
| | | | | | | (in thousands) | |
| COMMON SHAREHOLDER'S EQUITY | | | | | | $ 793,099 | $ 955,712 |
| PREFERRED STOCK: | | | | | | | |
| $100 Par Value - Authorized 2,250,000 shares | | | | | | | |
| $25 Par Value - Authorized 11,200,000 shares | | | | | | | |
| Series | Call Price December 31, 2000 | Number of Shares Redeemed Year Ended December 31, 2000 | 1999 | 1998 | Shares Outstanding December 31, 2000 | | |
| Not Subject to Mandatory Redemption: | | | | | | | |
| 4-1/8% | 106.125 | 3,750 | 97 | 771 | 55,389 | 5,539 | 5,914 |
| 4.56% | 102 | - | 150 | 650 | 14,412 | 1,441 | 1,441 |
| 4.12% | 102.728 | 1,375 | - | 200 | 17,556 | 1,756 | 1,893 |
| | | | | | | 8,736 | 9,248 |
| Subject to Mandatory Redemption: | | | | | | | |
| 5.90% (a,b) | | - | 15,000 | - | 152,000 | 15,200 | 15,200 |
| 6-1/4% (a,b) | | - | 10,000 | - | 192,500 | 19,250 | 19,250 |
| 6.30% (a,b) | | - | - | - | 132,450 | 13,245 | 13,245 |
| 6-7/8% (a,c) | | - | 10,000 | - | 172,500 | 17,250 | 17,250 |
| | | | | | | 64,945 | 64,945 |
| LONG-TERM DEBT (See Schedule of Long-term Debt): | | | | | | | |
| First Mortgage Bonds | | | | | | 308,976 | 356,820 |
| Installment Purchase Contracts | | | | | | 309,717 | 309,568 |
| Senior Unsecured Notes | | | | | | 397,435 | 297,282 |
| Other Long-term Debt | | | | | | 211,307 | 199,259 |
| Junior Debentures | | | | | | 161,504 | 161,397 |
| Less Portion Due Within One Year | | | | | | (90,000) | (198,000) |
| Long-term Debt Excluding Portion Due Within One Year | | | | | | 1,298,939 | 1,126,326 |
| TOTAL CAPITALIZATION | | | | | | $2,165,719 | $2,156,231 |

(a) Not callable until after 2002. There are no aggregate sinking fund provisions through 2002. Sinking fund provisions require the redemption of 15,000 shares in 2003 and 67,500 shares in each 2004 and 2005.

(b) Commencing in 2004 and continuing through 2008 the Company may redeem, at $100 per share, 20,000 shares of the 5.90% series, 15,000 shares of the 6-1/4% series and 17,500 shares of the 6.30% series outstanding under sinking fund provisions at its option and all remaining outstanding shares must be redeemed not later than 2009. Shares redeemed in 1999 and 1997 may be applied to meet the sinking fund requirement.

(c) Commencing in 2003 and continuing through the year 2007, a sinking fund will require the redemption of 15,000 shares each year and the redemption of the remaining shares outstanding on April 1, 2008, in each case at $100 per share. Shares redeemed in 1999 and 1997 may be applied to meet the sinking fund requirement.

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

First mortgage bonds outstanding were as follows:

| % Rate | Due | December 31, 2000 | December 31, 1999 |
|---|---|---|---|
| | | (in thousands) | |
| 6.40 | 2000 - March 1 | $ - | $ 48,000 |
| 7.63 | 2001 - June 1 | 40,000 | 40,000 |
| 7.60 | 2002 - November 1 | 50,000 | 50,000 |
| 7.70 | 2002 - December 15 | 40,000 | 40,000 |
| 6.10 | 2003 - November 1 | 30,000 | 30,000 |
| 8.50 | 2022 - December 15 | 75,000 | 75,000 |
| 7.35 | 2023 - October 1 | 20,000 | 20,000 |
| 7.20 | 2024 - February 1 | 30,000 | 30,000 |
| 7.50 | 2024 - March 1 | 25,000 | 25,000 |
| Unamortized Discount | | (1,024) | (1,180) |
| | | $308,976 | $356,820 |

Certain indentures relating to the first mortgage bonds contain improvement, maintenance and replacement provisions requiring the deposit of cash or bonds with the trustee, or in lieu thereof, certification of unfunded property additions.

Installment purchase contracts have been entered into, in connection with the issuance of pollution control revenue bonds by governmental authorities as follows:

| % Rate | Due | December 31, 2000 | December 31, 1999 |
|---|---|---|---|
| | | (in thousands) | |
| City of Lawrenceburg, Indiana: | | | |
| 7.00 | 2015 - April 1 | $ 25,000 | $ 25,000 |
| 5.90 | 2019 - November 1 | 52,000 | 52,000 |
| City of Rockport, Indiana: | | | |
| (a) | 2014 - August 1 | 50,000 | 50,000 |
| 7.60 | 2016 - March 1 | 40,000 | 40,000 |
| 6.55 | 2025 - June 1 | 50,000 | 50,000 |
| (b) | 2025 - June 1 | 50,000 | 50,000 |
| City of Sullivan, Indiana: | | | |
| 5.95 | 2009 - May 1 | 45,000 | 45,000 |
| Unamortized Discount | | (2,283) | (2,432) |
| | | $309,717 | $309,568 |

(a) A variable interest rate is determined weekly. The average weighted interest rate was 4.5% for 2000 and 3.2% for 1999.
(b) An adjustable interest rate can be a daily, weekly, commercial paper or term rate as designated by I&M. A weekly rate was selected which ranged from 2.9% to 5.9% in 2000 and from 2.2% to 5.6% in 1999 and averaged 4.2% and 3.2% during 2000 and 1999, respectively.

Under the terms of the installment purchase contracts, I&M is required to pay amounts sufficient to enable the cities to pay interest on and the principal (at stated maturities and upon mandatory redemptions) of related pollution control revenue bonds issued to finance the construction of pollution control facilities at certain generating plants. On the two variable rate series the principal is payable at the stated maturities or on the demand of the bondholders at periodic interest adjustment dates which occur weekly. The variable rate bonds due in 2014 are supported by a bank letter of credit which expires in 2002. I&M has agreements that provide for brokers to remarket the adjustable rate bonds due in 2025 tendered at interest adjustment dates. In the event certain bonds cannot be remarketed, I&M has a standby bond purchase agreement with a bank that provides for the bank to purchase any bonds not remarketed. The purchase agreement expires in 2001. Accordingly, the variable and adjustable rate installment purchase contracts have been classified for repayment purposes based on the expiration dates of the standby purchase agreement and the letter of credit.

Senior unsecured notes outstanding were as follows:

| % Rate | Due | December 31, 2000 | December 31, 1999 |
|---|---|---|---|
| | | (in thousands) | |
| (a) | 2000 - November 22 | $ - | $100,000 |
| (b) | 2002 - September 3 | 200,000 | - |
| 6-7/8 | 2004 - July 1 | 150,000 | 150,000 |
| 6.45 | 2008 - November 10 | 50,000 | 50,000 |
| Unamortized Discount | | (2,565) | (2,718) |
| | | $397,435 | $297,282 |

(a) A floating interest rate is determined monthly. The rate on December 31, 1999 was 7.1%.
(b) A floating interest rate is determined quarterly. The rate on December 31, 2000 was 7.31%.

Junior debentures outstanding were as follows:

| % Rate | Due | December 31, 2000 | 1999 |
|---|---|---|---|
| | | (in thousands) | |
| 8.00 | 2026 - March 31 | $ 40,000 | $ 40,000 |
| 7.60 | 2038 - June 30 | 125,000 | 125,000 |
| Unamortized Discount | | (3,496) | (3,603) |
| Total | | $161,504 | $161,397 |

Interest may be deferred and payment of principal and interest on the junior debentures is subordinated and subject in right to the prior payment in full of all senior indebtedness of I&M.

At December 31, 2000, future annual long-term debt payments are as follows:

| | Amount (in thousands) |
|---|---|
| 2001 | $ 90,000 |
| 2002 | 340,000 |
| 2003 | 30,000 |
| 2004 | 150,000 |
| 2005 | - |
| Later Years | 788,307 |
| Total Principal Amount | 1,398,307 |
| Unamortized Discount | (9,368) |
| Total | $1,388,939 |

## INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
### Index to Notes to Consolidated Financial Statements

The notes listed below are combined with the notes to financial statements for AEP and its other subsidiary registrants. The combined footnotes begin on page L-1.



| | Combined Footnote Reference |
|---|---|
| Significant Accounting Policies | Note 1 |
| Merger | Note 3 |
| Nuclear Plant Restart | Note 4 |
| Rate Matters | Note 5 |
| Effects of Regulation | Note 6 |
| Industry Restructuring | Note 7 |
| Commitments and Contingencies | Note 8 |
| Staff Reductions | Note 11 |
| Benefit Plans | Note 12 |
| Business Segments | Note 14 |
| Financial Instruments, Credit and Risk Management | Note 15 |
| Income Taxes | Note 16 |
| Supplementary Information | Note 17 |
| Leases | Note 18 |
| Lines of Credit and Factoring of Receivables | Note 19 |
| Unaudited Quarterly Financial Information | Note 20 |
| Related Party Transactions | Note 23 |

## INDEPENDENT AUDITORS' REPORT

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

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Indiana Michigan Power Company and its subsidiaries as of December 31, 2000 and 1999, and the related consolidated statements of income, retained earnings, and cash flows for each of the three years in the period ended December 31, 2000. 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 auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes 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 its subsidiaries as of December 31, 2000 and 1999, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2000 in conformity with accounting principles generally accepted in the United States of America.

DELOITTE & TOUCHE LLP
Columbus, Ohio
February 26, 2001

## NOTES TO FINANCIAL STATEMENTS

The notes to financial statements that follow are a combined presentation for AEP and its subsidiary registrants. The following list of footnotes shows the registrant to which they apply:

| | |
|---|---|
| 1. Significant Accounting Policies | AEP, AEGCo, APCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, WTU |
| 2. Extraordinary Items | AEP, APCo, CPL, CSPCo, OPCo, SWEPCo, WTU |
| 3. Merger | AEP, CPL, I&M, KPCo, PSO, SWEPCo, WTU |
| 4. Nuclear Plant Restart | AEP, I&M |
| 5. Rate Matters | AEP, APCo, CPL, CSPCo, I&M, KPCo, OPCo, OPCo, SWEPCo, WTU |
| 6. Effects of Regulation | AEP, AEGCo, APCo, CPL, CSPCo, I&M, KPCo, KPCo, OPCo, PSO, SWEPCo, WTU |
| 7. Industry Restructuring | AEP, APCo, CPL, CSPCo, I&M, OPCo, PSO, SWEPCo, WTU |
| 8. Commitments and Contingencies | AEP, AEGCo, APCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, WTU |
| 9. Acquisitions | AEP |
| 10. International Investments | AEP |
| 11. Staff Reductions | AEP, APCo, CSPCo, I&M, KPCo, OPCo |
| 12. Benefit Plans | AEP, APCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, WTU |
| 13. Stock Based Compensation | AEP |
| 14. Business Segments | AEP, AEGCo, APCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, WTU |
| 15. Financial Instruments, Credit and Risk Management | AEP, AEGCo, APCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, WTU |
| 16. Income Taxes | AEP, AEGCo, APCo, CPL, CSPCo, I&M, KPCo, KPCo, OPCo, PSO, SWEPCo, WTU |
| 17. Supplementary Information | AEP, APCo, CSPCo, I&M, OPCo |
| 18. Leases | AEP, AEGCo, APCo, CSPCo, I&M, KPCo, OPCo |
| 19. Lines of Credit and Commitment Fees | AEP, AEGCo, APCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, WTU |
| 20. Unaudited Quarterly Financial Information | AEP, AEGCo, APCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, WTU |
| 21. Trust Preferred Securities | AEP, CPL, PSO, SWEPCo, |

| | |
|---|---|
| 22. Jointly Owned Electric Utility Plant | CPL, CSPCo, PSO, SWEPCo, WTU |
| 23. Related Party Transactions | AEGCo, APCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, WTU |

## 1. Significant Accounting Policies:

*Business Operations* – AEP's principal business conducted by its eleven domestic electric utility operating companies is the generation, transmission and distribution of electric power. Nine of AEP's eleven domestic electric utility operating companies, APCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, WTU, are SEC registrants. AEGCo is a domestic generating company wholly-owned by AEP that is an SEC registrant. These companies are subject to regulation by the FERC under the Federal Power Act and follow the Uniform System of Accounts prescribed by FERC. They are subject to further regulation with regard to rates and other matters by state regulatory commissions.

Wholesale marketing and trading of electricity and gas is conducted in the United States and Europe. In addition AEP's domestic operations includes non-regulated independent power and cogeneration facilities and an intra-state midstream natural gas operation in Louisiana.

AEP's international operations include regulated supply and distribution of electricity and other non-regulated power generation projects in the United Kingdom, Australia, Mexico, South America and China.

In addition to the above energy related operations, AEP is also involved in domestic factoring of accounts receivable, investing in leveraged leases and providing energy services worldwide and communications related services domestically.

*Rate Regulation* – The AEP System is subject to regulation by the SEC under the PUHCA. The rates charged by the domestic utility subsidiaries are approved by the FERC and the state utility commissions. The FERC regulates wholesale electricity operations and transmission rates and the state commissions regulate retail generation and distribution rates. The prices charged by foreign subsidiaries located in the UK, Australia, China, Mexico and Brazil are regulated by the authorities of that country and are generally subject to price controls.

*Principles of Consolidation* – AEP's consolidated financial statements include AEP Co., Inc. and its wholly-owned and majority-owned subsidiaries consolidated with their wholly-owned subsidiaries. The consolidated financial statements for APCo, CPL, CSPCo, I&M, OPCo, PSO and SWEPCo include the registrant and its wholly-owned subsidiaries. Significant intercompany items are eliminated in consolidation. Equity investments that are 50% or less owned are accounted for using the equity method with their equity earnings included in Other Income, net for AEP and nonoperating income for the registrant subsidiaries.

*Basis of Accounting* - As cost-based rate-regulated electric public utility companies, the financial statements for AEP and each of the registrant subsidiaries reflect the actions of regulators that result in the recognition of revenues and expenses in different time periods than enterprises that are not rate regulated. In accordance with SFAS 71, "Accounting for the Effects of Certain Types of Regulation," regulatory assets (deferred expenses) and regulatory liabilities (deferred revenues) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues. Application of SFAS 71 for the generation portion of the business was discontinued as follows: in Ohio by OPCo and CSPCo in September 2000, in Virginia and West Virginia by APCo in June 2000, in Texas by CPL, WTU, and SWEPCo in September 1999 and in Arkansas by SWEPCo in September 1999. See Note 7, "Industry Restructuring" for additional information.

*Use of Estimates* - The preparation of these financial statements in conformity with generally accepted accounting principles requires in certain instances the use of estimates and assumptions that affect the reported amounts of assets and liabilities along with the disclosure of contingent liabilities at the date of financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

*Property, Plant and Equipment* – Domestic electric utility property, plant and equipment are stated at original cost of the acquirer. The property, plant and equipment of SEEBOARD, CitiPower and LIG are stated at their fair market value at acquisition plus the original cost of property acquired or constructed since the acquisition, less disposals. Additions, major replacements and betterments are added to the plant accounts. For cost-based rate regulated operations retirements from the plant accounts and associated removal costs, net of salvage, are deducted from accumulated depreciation. The costs of labor, materials and overheads incurred to operate and maintain plant are included in operating expenses.

*Allowance for Funds Used During Construction (AFUDC)* - AFUDC is a noncash nonoperating income item that is capitalized and recovered through depreciation over the service life of domestic regulated electric utility plant. For domestic regulated electric utility plant, it represents the estimated cost of borrowed and equity funds used to finance construction projects. The amounts of AFUDC for 2000, 1999 and 1998 were not significant. Effective with the discontinuance of the application of SFAS 71 regulatory accounting for domestic generating assets in Arkansas, Ohio, Texas, Virginia and West Virginia and for AEP's other nonregulated operations interest is capitalized during construction in accordance with SFAS 34, "Capitalization of Interest Costs." The amounts of interest capitalized was not material in 2000, 1999, and 1998.

*Depreciation, Depletion and Amortization* - Depreciation of property, plant and equipment is provided on a straight-line basis over the estimated useful lives of property, other than coal-mining property, and is calculated largely through the use of composite rates by functional class as follows:

| Functional Class of Property | Annual Composite Depreciation Rates Ranges 2000 |
|---|---|
| Production: | |
| Steam-Nuclear | 2.8% to 3.4% |
| Steam-Fossil-Fired | 2.3% to 4.5% |
| Hydroelectric-Conventional and Pumped Storage | 2.7% to 3.4% |
| Transmission | 1.7% to 3.1% |
| Distribution | 3.3% to 4.2% |
| Other | 2.5% to 20.0% |

| Functional Class of Property | Annual Composite Depreciation Rates Ranges 1999 |
|---|---|
| Production: | |
| Steam-Nuclear | 2.8% to 3.4% |
| Steam-Fossil-Fired | 3.2% to 5.0% |
| Hydroelectric-Conventional and Pumped Storage | 2.7% to 3.4% |
| Transmission | 1.7% to 2.7% |
| Distribution | 2.8% to 4.2% |
| Other | 2.0% to 20.0% |

| Functional Class of Property | Annual Composite Depreciation Rates Ranges 1998 |
|---|---|
| Production: | |
| Steam-Nuclear | 2.8% to 3.4% |
| Steam-Fossil-Fired | 3.2% to 4.4% |
| Hydroelectric-Conventional and Pumped Storage | 2.7% to 3.4% |
| Transmission | 1.7% to 2.7% |
| Distribution | 3.3% to 4.2% |
| Other | 2.5% to 20.0% |

The following table provides the annual composite depreciation rates generally used by the AEP registrant subsidiaries for the years 2000, 1999 and 1998 which were as follows:

| | Nuclear | Steam | Hydro | Transmission | Distribution | General |
|---|---|---|---|---|---|---|
| AEGCo | - % | 3.5% | - % | - % | - % | 2.8% |
| APCo | - | 3.4 | 2.9 | 2.2 | 3.3 | 3.2 |
| CPL | 2.8 | 2.3 | - | 2.3 | 3.5 | 4.2 |
| CSPCo | - | 3.2 | - | 2.3 | 3.6 | 3.3 |
| I&M | 3.4 | 4.5 | 3.4 | 1.9 | 4.2 | 3.8 |
| KPCo | - | 3.8 | - | 1.7 | 3.5 | 2.5 |
| OPCo | - | 3.4 | 2.7 | 2.3 | 4.0 | 2.7 |
| PSO | - | 2.7 | - | 2.3 | 3.4 | 6.4 |
| SWEPCo | - | 3.3 | - | 2.7 | 3.6 | 4.6 |
| WTU | - | 2.7 | - | 3.1 | 3.3 | 6.8 |

Depreciation, depletion and amortization of OPCo's coal-mining assets is provided over each asset's estimated useful life or the estimated life of the mine, whichever is shorter, and is calculated using the straight-line method for mining structures and equipment. The units-of-production method is used to amortize coal rights and mine development costs based on estimated recoverable tonnages at a current average rate of $5.07 per ton in 2000, $2.32 per ton in 1999 and $1.85 per ton in 1998. These costs are included in the cost of coal charged to fuel expense. See Note 5 "Rate Matters" regarding the closure and possible sale of affiliated mines.

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

*Inventory* – Except for CPL, PSO and WTU, the domestic utility companies value fossil fuel inventories using a weighted average cost method. CPL, PSO and WTU, utilize the LIFO method to value fossil fuel inventories. SWEPCo continues to use the weighted average cost method pending approval of its request to the Arkansas Commission to utilize the LIFO method. Natural gas inventories held by LIG are marked-to-market.

*Accounts Receivable* – AEP Credit Inc. (formerly CSW Credit) factors accounts receivable for the domestic utility subsidiaries, except APCo, and unaffiliated companies.

*Foreign Currency Translation* - The financial statements of subsidiaries outside the U.S. which are included in AEP's consolidated financial statements are measured using the local currency as the functional currency and translated into U.S. dollars in accordance with SFAS 52 "Foreign Currency Translation". Assets and liabilities are translated to U.S. dollars at year-end rates of exchange and revenues and expenses are translated at monthly average exchange rates throughout the year. Currency translation gain and loss adjustments are recorded in shareholders' equity as "Accumulated Other Comprehensive Income (Loss)". The non-cash impact of the changes in exchange rates on cash, resulting from the translation of items at different exchange rates is shown on AEP's Consolidated Statement of Cash Flows in "Effect of Exchange Rate Change on Cash." Actual currency transaction gains and losses are recorded in income.

*Energy Marketing and Trading Transactions* - The AEP System engages in wholesale electricity and natural gas marketing and trading transactions (trading activities). Trading activities involve the sale of energy under physical forward contracts at fixed and variable prices and the trading of energy contracts including exchange traded futures and options, over-the-counter options and swaps. The majority of these transactions represent physical forward electricity contracts in AEP's traditional marketing area (up to two transmission systems from AEP's service territory) and are typically settled by entering into offsetting contracts. The net revenues from these transactions in AEP's traditional marketing area are included in revenues from domestic electric utility operations on AEP's consolidated statements of income.

The AEP System also purchases and sells electricity and gas options, futures and swaps, and enters into forward purchase and sale contracts for electricity (outside its traditional marketing area) and gas. These transactions represent non-regulated trading activities that are included in revenues from worldwide electric and gas operations on AEP's consolidated statements of income.

All of the registrant subsidiaries except AEGCo participate in the AEP System's wholesale marketing and trading of electricity. APCo, CSPCo, I&M, KPCo and OPCo record revenues from trading of electricity net of purchases as operating revenues for forward electricity trades in AEP's traditional marketing area and as nonoperating income for forward electricity trades beyond two transmission systems from AEP and for speculative financial transactions (options, futures and swaps). CPL, PSO, SWEPCo and WTU record revenues from trading of electricity net of purchases as operating revenues.

The AEP System follows EITF 98-10 and EITF 00-17, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities" and "Measuring the Fair Value of Energy-Related Contracts in Applying Issue 98-10", respectively. EITF 98-10 requires that all energy trading contracts be marked-to-market. The effect on AEP's consolidated statements of income of marking open trading contracts to market in the regulated jurisdictions are deferred as regulatory assets or liabilities for those open electricity trading transactions within AEP's marketing area that are included in cost of service on a settlement basis for ratemaking purposes. Non-regulated jurisdictions with open electricity trading transactions within AEP's marketing area are marked-to-market and included in domestic electric utility operations revenues on AEP's consolidated statements of income. Non-regulated and regulated jurisdictions open electricity trading contracts outside the traditional marketing area are accounted for on a mark-to-market basis and included in worldwide electric and gas operations revenues on AEP's consolidated statements of income. Open gas trading contracts are accounted for on a mark-to-market basis and included in worldwide electric and gas operations on AEP's consolidated statements of income.

APCo, CSPCo and OPCo account for open forward electricity trading contracts on a mark-to-market basis and include the mark-to-market change in revenues for open contracts in AEP's traditional marketing area and in nonoperating income for open contracts beyond AEP's traditional marketing area.

I&M and KPCo account for open forward electricity trading contracts on a mark-to-market basis and defer the mark-to-market change as regulatory assets or liabilities for those open contracts in AEP's traditional marketing area and include the mark-to-market change in nonoperating income for open contracts beyond AEP's traditional marketing area.

CPL, PSO, SWEPCo and WTU account for open forward electricity trading contracts on a mark-to-market basis. CPL includes the mark-to-market change for open electricity trading contracts in revenues. PSO defers as regulatory assets or liabilities the mark-to-market change for open forward electricity trading contracts that are included in cost of service on a settlement basis for ratemaking purposes. SWEPCo and WTU include the jurisdictional share of the mark-to-market change in revenues for open electricity trading contracts for those jurisdictions that are not subject to SFAS 71 cost based rate regulation and defer as regulatory assets or liabilities the jurisdictional share of the mark-to-market change for open contracts that are included in cost of service on a settlement basis for ratemaking purposes.

Unrealized mark-to-market gains and losses from all trading activity are reported as assets and liabilities, respectively.

*Hedging and Related Activities* – In order to mitigate the risks of market price and interest rate fluctuations, AEP's foreign subsidiaries, SEEBOARD and CitiPower, utilize interest swaps, currency swaps and forward contracts to hedge such market fluctuations. Changes in the market value of these swaps and contracts are deferred until the gain or loss is realized on the underlying hedged asset, liability or commodity. To qualify as a hedge, these transactions must be designated as a hedge and changes in their fair value must correlate with changes in the price and interest rate movement of the underlying asset, liability or commodity. This in effect reduces AEP's exposure to the effects of market fluctuations related to price and interest rates.

AEP, APCo, CSPCo, I&M, and OPCo enter into contracts to manage the exposure to unfavorable changes in the cost of debt to be issued. These anticipatory debt instruments are entered into in order to manage the change in interest rates between the time a debt offering is initiated and the issuance of the debt (usually a period of 60 days). Gains or losses from these transactions are deferred and amortized over the life of the debt issuance with the amortization included in interest charges. There were no such forward contracts outstanding at December 31, 2000 or 1999. See Note 15 – "Financial Instruments, Credit and Risk Management" for further discussion of the accounting for risk management transactions.

*Revenues and Fuel Costs* - Domestic revenues include the accrual of service provided but unbilled at month-end as well as billed revenues. The cost of fuel consumed is charged to expense as incurred. Under governing regulatory commission retail rate orders, any resulting fuel cost over or under-recoveries are deferred as regulatory liabilities or regulatory assets in accordance with SFAS 71. These deferrals generally are billed or refunded to customers in later months with the regulator's review and approval. Wholesale jurisdictional fuel cost increases and decreases over amounts included in base rates are expensed and billed as incurred. See Note 5 "Rate Matters" and Note 7 "Industry Restructuring" for further information about fuel recovery.

*Levelization of Nuclear Refueling Outage Costs* - In order to match costs with regulated revenues, which include outage costs on a normalized basis, incremental operation and maintenance costs associated with periodic refueling outages at I&M's Cook Plant are deferred and amortized over the period beginning with the commencement of an outage and ending with the beginning of the next outage.

*Amortization of Cook Plant Deferred Restart Costs* - Pursuant to settlement agreements approved by the IURC and the MPSC to resolve all issues related to an extended outage of the Cook Plant, I&M deferred $200 million of incremental operation and maintenance costs during 1999. The deferred amount is being amortized to expense on a straight-line basis over five years from January 1, 1999 to December 31, 2003. I&M amortized $40 million in 1999 and 2000, leaving $120 million as an SFAS 71 regulatory asset at December 31, 2000 on the Consolidated Balance Sheets of AEP and I&M.

*Income Taxes* - The AEP System follows the liability method of accounting for income taxes as prescribed by SFAS 109, "Accounting for Income Taxes." Under the liability method, deferred income taxes are provided for all temporary differences between the book cost and tax basis of assets and liabilities which will result in a future tax consequence. Where the flow-through method of accounting for temporary differences is reflected in regulated revenues (that is, 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 in accordance with SFAS 71 to match the regulated revenues and tax expense.

*Investment Tax Credits* - Investment tax credits have been 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 being amortized over the life of the regulated plant investment.

*Debt and Preferred Stock* – Where appropriate gains and losses from the reacquisition of debt used to finance domestic regulated electric utility plant are generally deferred and amortized over the remaining term of the reacquired debt in accordance with their rate-making treatment. If the debt is refinanced, the reacquisition costs attributable to the portions of the business that are subject to cost based regulatory accounting under SFAS 71 are generally deferred and amortized over the term of the replacement debt commensurate with their recovery in rates. Gains and losses on the reacquisition of debt for operations not subject to SFAS 71 are reported as a component of net income.

Debt discount or premium and debt issuances expenses are deferred and amortized over the term of the related debt, with the amortization included in interest charges.

Where rates are regulated redemption premiums paid to reacquire preferred stock of the domestic utility subsidiaries are included in paid-in capital and amortized to retained earnings commensurate with their recovery in rates. The excess of par value over costs of preferred stock reacquired is credited to paid-in capital and amortized to retained earnings consistent with the timing of its recovery in rates in accordance with SFAS 71.

*Goodwill* – The amount of acquisition cost in excess of the fair value allocated to tangible assets obtained through an acquisition accounted for as a purchase combination is recorded as goodwill on AEP's consolidated balance sheet. Amortization of goodwill is on a straight-line basis generally over 40 years except for the portion of goodwill associated with gas trading and marketing activities which is being amortized on a straight-line basis over 10 years. The recoverability of goodwill (evaluated on undiscounted operating cash flow analysis) is reviewed when events or changes in circumstances indicate that the carrying amount may exceed fair value.

*Other Assets* - Other assets on AEP's consolidated balance sheet are comprised primarily of nuclear decommissioning and spent nuclear fuel disposal trust funds and licenses for CitiPower operating franchises. Securities held in trust funds for decommissioning nuclear facilities and for the disposal of spent nuclear fuel are included in Other Assets at market value in accordance with SFAS 115, "Accounting for Certain Investments in Debt and Equity Securities." Securities in the trust funds have been classified as available-for-sale due to their long-term purpose. Under the provisions of SFAS 71, unrealized gains and losses from securities in these trust funds are not reported in equity but result in adjustments to the 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.

*Comprehensive Income* - Comprehensive income is defined as the change in equity (net assets) of a business enterprise during a period from transactions and other events and circumstances from non-owner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners. There were no material differences between net income and comprehensive income for AEGCo, APCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, and WTU.

*Components of Other Comprehensive Income* – The following table provides the components that comprise the balance sheet amount in Accumulated Other Comprehensive Income for AEP.

| Components | December 31, 2000 | 1999 | 1998 |
|---|---|---|---|
| | (millions) | | |
| Foreign Currency Adjustments | $ (99) | $ 20 | $ 33 |
| Unrealized Losses on Securities | - | (20) | (20) |
| Minimum Pension Liability | (4) | (4) | (6) |
| | $(103) | $ (4) | $ 7 |

*Segment Reporting* – The AEP System has adopted SFAS No. 131, which requires disclosure of selected financial information by business segment as viewed by the chief operating decision-maker. See Note 14 "Business Segments" for further discussion and details regarding segments.

*Common Stock Options* – AEP follows Accounting Principles Board Opinion 25 to account for stock options. Compensation expense is not recognized at the date of grant, because the exercise price of stock options awarded under the stock option plan equals the market price of the underlying stock on the date of grant.

*EPS* – AEP's basic earnings per share is determined based upon the weighted average number of common shares outstanding during the years presented. Diluted earnings per share for AEP is based upon the weighted average number of common shares and stock options outstanding during the years presented. Basic and diluted are the same in 2000, 1999 and 1998.

AEGCo, APCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, and WTU are wholly-owned subsidiaries of AEP and are not required to report EPS.

*Reclassification* - Certain prior year financial statement items have been reclassified to conform to current year presentation. Such reclassification had no impact on previously reported net income.

**2. Extraordinary Items:**

*Extraordinary Items* – Extraordinary items were recorded for the discontinuance of regulatory accounting under SFAS 71 for the generation portion of the business in the Ohio, Virginia, West Virginia, Texas and Arkansas state jurisdictions. See Note 7 "Industry Restructuring" for descriptions of the restructuring plans and related accounting effects. The following table shows the components of the extraordinary items reported on AEP's consolidated statements of income:

| | Year Ended December 31, 2000 | 1999 |
|---|---|---|
| | (in millions) | |
| Extraordinary Items: | | |
| Discontinuance of Regulatory Accounting for Generation: | | |
| Ohio Jurisdiction (Net of Tax of $35 Million) | $(44) | $ - |
| Virginia and West Virginia Jurisdictions (Inclusive of Tax Benefit of $8 Million) | 9 | - |
| Texas and Arkansas Jurisdictions (Net of Tax of $5 Million) | - | (8) |
| Loss on Reacquired Debt (Net of Tax of $3 Million) | - | (6) |
| Extraordinary Items | $(35) | $(14) |

There were no extraordinary items in 1998.

**3. Merger:**

On June 15, 2000, AEP merged with CSW so that CSW became a wholly-owned subsidiary of AEP. Under the terms of the merger agreement, approximately 127.9 million shares of AEP Common Stock were issued in exchange for all the outstanding shares of CSW Common Stock based upon an exchange ratio of 0.6 share of AEP Common Stock for each share of CSW Common Stock. Following the exchange, former shareholders of AEP owned approximately 61.4 percent of the corporation, while former CSW shareholders owned approximately 38.6 percent of the corporation.

The merger was accounted for as a pooling of interests. Accordingly, AEP's consolidated financial statements give retroactive effect to the merger, with all periods presented as if AEP and CSW had always been combined. Certain reclassifications have been made to conform the historical financial statement presentation of AEP and CSW.

The following table sets forth revenues, extraordinary items and net income previously reported by AEP and CSW and the combined amounts shown in the accompanying financial statements for 1999 and 1998:

| | Year Ended December 31, 1999 | 1998 |
|---|---|---|
| | (in millions) | |
| Revenues: | | |
| AEP | $ 6,870 | $ 6,358 |
| CSW | 5,537 | 5,482 |
| AEP After Pooling | $12,407 | $11,840 |

| | Year Ended December 31, 1999 | 1998 |
|---|---|---|
| | (in millions) | |
| Extraordinary Items: | | |
| AEP | $ - | $ - |
| CSW | (14) | - |
| AEP After Pooling | $(14) | $ - |
| Net Income: | | |
| AEP | $520 | $536 |
| CSW | 455 | 440 |
| Conforming Adjustment | (3) | (1) |
| AEP After Pooling | $972 | $975 |

The combined financial statements include an adjustment to conform CSW's accounting for vacation pay accruals with AEP's accounting. The effect of the conforming adjustment was to reduce net assets by $16 million at December 31, 1999 and reduce net income by $3 million and $1 million for the years ended December 31, 1999 and 1998, respectively.

The following table shows the vacation accrual conforming adjustment for CSW's registrant utility subsidiaries:

| | Net Asset Reduction At December 31, 1999 (in millions) | Net Income Reductions Year Ended December 31, 1999 | 1998 |
|---|---|---|---|
| | | (in millions) | |
| CPL | $5.3 | $0.7 | $0.1 |
| PSO | 2.8 | 1.1 | - |
| SWEPCo | 4.5 | 0.5 | 0.1 |
| WTU | 2.6 | 0.4 | 0.1 |

In connection with the merger, $203 million ($180 million after tax) of non-recoverable merger costs were expensed by AEP through December 31, 2000. Such costs included transaction and transition costs not recoverable from ratepayers. Also included in the merger costs were non-recoverable change in control payments. Merger transaction and transition costs of $45 million recoverable from ratepayers were deferred pursuant to state regulator approved settlement agreements. The deferred merger costs are being amortized over five to eight year recovery periods depending on the specific terms of the settlement agreements, with the amortization ($4 million for AEP for the year 2000) included in depreciation and amortization expense.

The following table shows the deferred merger cost and amortization expense of the applicable subsidiary registrants:

| | Merger Cost Deferral at December 31, 2000 | Amortization Expense for the Year Ended December 31, 2000 |
|---|---|---|
| | (in millions) | |
| CPL | $15.7 | $1.3 |
| I&M | 7.6 | 0.7 |
| KPCo | 2.7 | 0.3 |
| PSO | 8.3 | 0.5 |
| SWEPCo | 6.6 | 0.5 |
| WTU | 4.6 | 0.4 |

Merger transition costs are expected to continue to be incurred for several years after the merger and will be expensed or deferred for amortization as appropriate. The state settlement agreements provide for, among other things, a sharing of net merger savings with certain regulated customers over periods of up to eight years through rate reductions beginning in the third quarter of 2000. In connection with the merger, the PUCT approved a settlement agreement that provides for, among other things, sharing net merger savings with Texas customers of CPL, SWEPCo and WTU over six years after consummation of the merger through rate reduction riders. The settlement agreement results in rate reductions for Texas customers totaling $221 million over a six-year period commencing with the merger's consummation. The rate reduction was composed of $84 million of net merger savings and $137 million to resolve issues associated with CPL's, SWEPCo's and WTU's rate and fuel reconciliation proceedings in Texas. Under the terms of the settlement agreement, base rates cannot be increased until three years after consummation of the merger.

The IURC and MPSC approved merger settlement agreements that, among other things, provide for sharing net merger savings with I&M's retail customers over eight years through reductions to customers' bills. The terms of the Indiana settlement require reductions in customers' bills of approximately $67 million over eight years. Under the Michigan settlement, billing credits will be used to reduce customers' bills by approximately $14 million over eight years for net guaranteed merger savings. The Indiana settlement extends the base rate freeze in the Cook Plant extended outage settlement agreement until January 1, 2005 and requires additional annual deposits of $6 million to the nuclear decommissioning trust fund for the

Indiana jurisdiction for the years 2001 through 2003. As a result of an appeal of the Indiana settlement agreement by a consumer group, I&M has not reflected the reductions in Indiana jurisdictional customers' bills. Instead, pending the result of the appeal, I&M recorded a liability ($1 million at December 31, 2000) for the reduction due to its Indiana customers under the settlement.

The KPSC approved a settlement agreement that, among other things, provides for sharing net merger savings with KPCo's customers over eight years through reductions to customers' bills and prohibits a general increase in base rates or other charges for three years following consummation of the merger. The Kentucky customers' share of the net merger savings is expected to be approximately $28 million.

A merger settlement agreement for PSO was approved by the Oklahoma Corporation Commission that, among other things, provides for sharing approximately $28 million in guaranteed net merger savings over five years with Oklahoma customers, prohibits an increase in Oklahoma base rates prior to January 1, 2003 and requires an application to join an RTO be filed with FERC by December 31, 2001.

The Arkansas Commission approved an agreement related to the merger which, among other things, provides for $6 million of net merger savings to reduce SWEPCo customers rates over five years in Arkansas and prohibits a base rate increase being effective prior to January 1, 2002.

SWEPCo's Louisiana customers will receive approximately $18 million of merger savings over eight years according to a merger approval order issued by the Louisiana Public Service Commission. In addition, the order capped base rates for five years after the consummation of the merger (until June 2005) and required that benefits from off-system sales be shared with ratepayers.

If actual merger savings are significantly less than the merger savings rate reductions required by the merger settlement agreements in the eight-year period following consummation of the merger, future results of operations, cash flows and possibly financial condition could be adversely affected.

Most of the merger settlement agreements approved by the regulatory commissions require the electric operating companies to join regional transmission organizations. APCo, CSPCo, I&M, KPCo, OPCo and several other unaffiliated utilities formed the Alliance RTO before the consummation of the merger. As a condition of FERC's approval of the merger, CPL, PSO, SWEPCo and WTU were required to join an RTO prior to December 31, 2000 and to transfer the operation and control of their transmission facilities to that RTO by December 15, 2001. CPL and WTU are members of ERCOT. PSO and SWEPCo are members of SPP. ERCOT and SPP are transmission pooling organizations in certain geographic areas of the U.S. whose goals include enhancement of bulk electric transmission reliability. The SPP has filed with FERC to be approved as an RTO. Due to the FERC's inaction on approving the SPP RTO, in December 2000 PSO and SWEPCo filed with the FERC requesting an extension of time to join an RTO until 75 days following the FERC's approval of an RTO for the SPP service area. Initial filings to gain FERC approval for the Alliance RTO were made and conditional approval was granted by the FERC. The Alliance RTO made compliance filings as requested by the FERC and these were accepted in January 2001. Final FERC approval of the SPP RTO is pending.

The divestiture of 1,904 MW of generating capacity was required as a condition of regulatory approval of the merger by the FERC and PUCT. Under the FERC-approved merger agreement the divestiture of 550 MW of generating capacity comprised of 300 MW of capacity in SPP and 250 MW of capacity in ERCOT is required. The FERC is requiring AEP and CSW to divest their entire ownership interest in and operational control of the entire generating facilities that produce the capacity to be divested. The FERC required divestiture of the identified ERCOT capacity must be completed by March 15, 2001 and for the SPP capacity by July 1, 2002. The FERC found that certain energy sales in SPP and ERCOT would be a reasonable and effective interim mitigation measure until the required SPP and ERCOT divestitures could be completed. In February 2001, AEP announced the sale of Frontera, one of the plants required to be divested by the settlement agreements approved by the FERC. The Texas settlement calls for the divestiture of a total of 1,604 MW of generating capacity within

Texas inclusive of 250 MW ordered to be divested by FERC. The Texas divestiture cannot proceed until two years after the merger closes to satisfy the requirements to use pooling-of-interests accounting treatment. The FERC divestiture is not limited by the pooling rules because it is regulatory ordered.

The current annual dividend rate per share of AEP Common Stock is $2.40. The dividends per share reported on the statements of income for prior periods represent pro forma amounts and are based on AEP's historical annual dividend rate of $2.40 per share. If the dividends per share reported for prior periods were based on the sum of the historical dividends declared by AEP and CSW, the annual dividend rate would be $2.60 per combined share for the years ended December 31, 1999 and 1998.

**4. Nuclear Plant Restart:**

The restart of both units of I&M's Cook Plant was completed with Unit 2 reaching 100% power on July 5, 2000 and Unit 1 achieving 100% power on January 3, 2001. Cook Plant is a 2,110 MW two-unit plant owned and operated by I&M under licenses granted by the NRC. I&M shut down both units of the Cook Plant in September 1997 due to questions regarding the operability of certain safety systems that arose during a NRC architect engineer design inspection.

Settlement agreements in the Indiana and Michigan retail jurisdictions that address recovery of Cook Plant related outage costs were approved in 1999. The IURC approved a settlement agreement in March 1999 that resolved all matters related to the recovery of replacement energy fuel costs and all outage/restart costs and related issues during the extended outage of the Cook Plant. The settlement agreement provided for, among other things, the deferral of unrecovered fuel revenues accrued between September 9, 1997 and December 31, 1999; the deferral of up to $150 million of restart related nuclear operation and maintenance costs in 1999 above the amount included in base rates; the amortization of the deferred fuel revenues and non-fuel operation and maintenance cost deferrals over a five-year period ending December 31, 2003; a freeze in base rates through December 31, 2003; and a fixed fuel recovery charge through March 1, 2004.

The regulatory approved deferrals were recorded in 1999 as a regulatory asset in accordance with SFAS 71.

In December 1999 the MPSC approved a settlement agreement for two open Michigan power supply cost recovery reconciliation cases that resolves all issues related to the Cook Plant extended outage. The settlement agreement limits I&M's ability to increase base rates and freezes the power supply cost recovery factor until January 1, 2004; permits the deferral of up to $50 million in 1999 of jurisdictional non-fuel nuclear operation and maintenance expenses; authorizes the amortization of power supply cost recovery revenues accrued from September 9, 1997 to December 31, 1999 and non-fuel nuclear operation and maintenance cost deferrals over a five-year period ending December 31, 2003. The regulatory approved deferrals were recorded in the fourth quarter of 1999.

The amounts of restart costs charged to other operation and maintenance expenses were as follows:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2000 | 1999 | 1998 |
| Costs Incurred | $297 | $ 289 | $78 |
| Deferred Pursuant to Settlement Agreements | - | (200) | - |
| Amortization of Deferrals | 40 | 40 | - |
| Charged to O&M Expense | $337 | $ 129 | $78 |

At December 31, 2000 and 1999, deferred restart costs of $120 million and $160 million, respectively, remained in regulatory assets to be amortized through 2003. Also pursuant to the settlement agreements, accrued fuel-related revenues of $38 million and $37 million in 2000 and 1999, respectively, were amortized. At December 31, 2000 and 1999, fuel-related revenues of $113 million and $150 million, respectively, were included in regulatory assets and will be amortized through December 31, 2003 for both jurisdictions.

The amortization of restart costs and fuel-related revenues deferred under Indiana and Michigan retail jurisdictional settlement agreements will adversely affect results of operations through December 31, 2003 when the amortization period ends. The annual amortization of restart cost and fuel-related revenue deferrals is $78 million.

## 5. Rate Matters:

*Texas Jurisdictional Fuel Filings* – AEP's Texas electric operating companies (CPL, SWEPCo and WTU) have been experiencing significant natural gas fuel price increases which have resulted in under-recoveries of fuel costs and the need to seek increases in fuel rates and surcharges to recover these under-recoveries.

*CPL Fuel Filings* - In July 2000 CPL filed with the PUCT an application to implement an increase in fuel factor revenues effective with the September 2000 billing month. Additionally, CPL proposed to implement an interim fuel surcharge to collect its under-recovered fuel costs, including accumulated interest, over a twelve-month period beginning in October 2000.

In September 2000 the PUCT approved a settlement. The settlement provided for an increase in fuel factor revenues of $173.5 million annually and provided for a two-phase surcharge totaling $86.4 million. The recovery of the first phase surcharge of $21.3 million for previously under-recovered fuel costs including accumulated interest for the period from December 1, 1999 through May 31, 2000 was authorized to be collected in September through December 2000. The second surcharge was not to exceed $65.1 million for projected under-recoveries for the period from June 2000 through August 2000 and was authorized to be collected January through September 2001. A September 2000 compliance filing showed the actual under-recovery for June 2000 through August 2000 to be $93.7 million. The remaining under-recovery amount of $28.6 was carried forward into a January 2001 filing.

In January 2001 CPL filed with the PUCT an application to implement an increase in fuel factors of $175.9 million, effective with the March 2001 billing month over the ten months March 2001 through December 2001. Additionally, CPL proposed to implement an interim fuel surcharge of $51.8 million, including accumulated interest, over a nine-month period beginning in April 2001 to collect its under-recovered fuel costs. Approval by the PUCT is pending.

*SWEPCo Fuel Filings* – In November 2000 SWEPCo filed with the PUCT an application for authority to implement an increase in fuel factor revenues effective with the January 2001 billing month. SWEPCo also proposed to implement an interim fuel surcharge to collect its under-recovered fuel costs, including accumulated interest, over a six-month period beginning in January 2001.

In January 2001 the PUCT approved SWEPCo's application. The order allows an increase in fuel factors of $12 million on an annual basis including accumulated interest beginning in January 2001 and a surcharge of $11.8 million for the billing months of February through July 2001.

In June 2000 SWEPCo filed with the PUCT an application for authority to reconcile fuel costs and to request authorization to carry the unrecovered balance forward into the next reconciliation period. During the reconciliation period of January 1, 1997 through December 31, 1999, SWEPCo incurred $347 million of Texas jurisdiction eligible fuel and fuel-related expenses.

On December 27, 2000, SWEPCo reached a settlement. The settlement resulted in a reduction of $2.25 million of eligible Texas jurisdictional fuel expense, which was prorated equally over thirty-six months of the reconciliation period. The settlement also provides that depreciation and lease expense associated with new aluminum railcars will qualify for treatment as eligible fuel expense from January 1, 2000 forward. Parties to the settlement will support SWEPCo in seeking to amend its 1999 excess earnings report to include 1999 railcar depreciation expense in the depreciation component of the calculation. In February 2001, the PUCT approved the settlement, which did not have a material effect on SWEPCo's results of operations.

*WTU Fuel Filings* – In August 2000 WTU filed with the PUCT an application for authority to implement an increase in fuel factors effective with the October 2000 billing month. WTU also proposed to implement an interim fuel surcharge to collect its under-recovered fuel costs from August 1, 1999 through June 30, 2000 including accumulated interest, over a six-month period beginning in November 2000.

In December 2000, the PUCT approved WTU's application. The order allows an increase in fuel factors of $42.6 million on an annual basis including accumulated interest and provides for a surcharge of $19.6 million for previously under-recovered fuel costs.

In January 2001 WTU filed with the PUCT an application for authority to implement an increase in fuel factor revenues of $46.5 million effective with the March 2001 billing. Approval by the PUCT is pending.

In December 2000 WTU filed with the PUCT an application for authority to reconcile fuel costs. During the reconciliation period of July 1, 1997 through June 30, 2000, WTU incurred $348 million of Texas jurisdiction eligible fuel and fuel-related expenses. Approval by the PUCT is pending.

*OPCo's Recovery of Fuel Costs* – Pursuant to PUCO – approved stipulation agreements the cost of coal burned at the Gavin Plant was subject to a 15-year predetermined price of $1.575 per million Btu's with quarterly escalation adjustments through November 2009. To the extent the actual cost of coal burned at the Gavin Plant was below the predetermined prices, the stipulation agreement provided OPCo with the opportunity to recover over its term the Ohio jurisdictional share of OPCo's investment in and the liabilities and future shutdown costs of its affiliated mines as well as any fuel costs incurred above the pre-determined rate and deferred for future recovery under the agreements. As a result of the Ohio Act introducing customer choice and a transition to market based pricing for electricity supply in Ohio, these stipulation agreements were superseded effective January 1, 2001. OPCo filed under the provisions of the Ohio Act for recovery of all of its generation related regulatory assets including fuel costs deferred under these predetermined price stipulation agreements. Under the terms of OPCo's PUCO-approved stipulated transition plan, recovery of generation-related regulatory assets at December 31, 2000, which were $518 million, over seven years was approved.

The Muskingum coal strip mine and Windsor deep coal mine which supplied all of their output to OPCo have been closed. Efforts are underway to reclaim the properties, sell or scrap all mining equipment, terminate both capital and operating leases and perform other activities necessary to reclaim the mines. Mine reclamation activities should be completed within two to three years; postremediation monitoring is anticipated to continue for five years after completion of reclamation.

OPCo currently plans to close the Meigs deep coal mine by the end of 2001 unless ongoing efforts to sell it are successful. Currently efforts are being made to sell the active Meigs and shutdown Windsor and Muskingum mines.

*FERC* - The FERC issued orders 888 and 889 in April 1996 which required each public utility that owns or controls interstate transmission facilities to file an open access network and point-to-point transmission tariff that offers services comparable to the utility's own uses of its transmission system. The orders also require utilities to functionally unbundle their services, and to pay their own transmission service tariffs in making off-system and third-party sales. As part of the orders, the FERC issued a pro-forma tariff, which reflects the Commission's views on the minimum non-price terms and conditions for non-discriminatory transmission service. The FERC orders also allow a utility to seek recovery of certain prudently-incurred stranded costs that result from unbundled transmission service.

On July 9, 1996, the AEP System companies filed an Open Access Transmission Tariff conforming with the FERC's pro-forma transmission tariff, subject to the resolution of certain pricing issues. The 1996 tariff incorporated transmission rates which were the result of a settlement of a pending rate case, but which were being collected subject to refund from certain customers who opposed the settlement and continued to litigate the reasonableness of AEP's transmission rates. On July 30, 1999, the FERC issued an order in the litigated rate case that would reduce AEP's rates for the affected customers below the settlement rate. AEP and certain of the affected customers sought rehearing of the Commission's Order.

On December 10, 1999, AEP filed a settlement agreement with the FERC resolving the issues on rehearing of the July 30, 1999 order. On March 16, 2000, the FERC approved the settlement agreement. Under terms of the settlement, the AEP System is required to make refunds retroactive to September 7, 1993 to certain customers affected by the July 30, 1999 FERC order. The refunds were made in two payments. Pursuant to FERC orders the first payment was made in February 2000 and the second payment was made on August 1, 2000. APCo, CSPCo, I&M, KPCo, and OPCo recorded provisions in 1999 and 2000 for the earnings impact of the required refunds including interest.

The settlement agreement also reduced the rates for transmission service. A new lower rate of $1.55 kw/month was made effective January 1, 2000, for all transmission service customers. Also as agreed, a new rate of $1.42 kw/month took effect on June 16, 2000 upon consummation of the AEP/CSW merger. Prior to January 1, 2000, the rate was $2.04 kw/month. Unless the market volume of physical power transactions grows to increase the utilization of the AEP System's transmission lines, the new open access transmission rate will adversely impact future results of operations and cash flows. Since the rate has been reduced the volume of transmission usage has increased on the AEP System mainly due to increased competition in the wholesale electricity market.

*West Virginia*

On May 12, 1999, APCo, an AEP subsidiary doing business in WV, filed with the WVPSC for a base rate increase of $50 million annually and a reduction in ENEC rates of $38 million annually. On February 7, 2000, APCo and other parties to the proceeding filed a Joint Stipulation with the WVPSC for approval.

The Joint Stipulation's main provisions include no change in either base or ENEC rates effective January 1, 2000 from those base and ENEC rates in effect from November 1, 1996 until December 31, 1999 (these rates provide for recovery of regulatory assets including any generation-related regulatory assets through frozen transition rates and a wires charge of 0.5 mills per KWH); the continued suspension of annual ENEC recovery proceedings and cessation of existing deferral accounting for all over or under recovery of fuel and purchased power costs net of system sales effective January 1, 2000; and the retention, as a regulatory liability, on the books of a net cumulative deferred ENEC overrecovery balance of $66 million as established by a WVPSC order on December 27, 1996. The Joint Stipulation also provides that when deregulation of generation occurs in WV, APCo will use this retained regulatory liability to reduce generation-related regulatory assets and, to the extent possible, any additional costs or obligations that restructuring and deregulation of APCo's generation business may impose. The elimination of ENEC recovery proceedings in WV will subject AEP and APCo to the risk of fuel market price increases and reductions in wholesale sales levels which could adversely affect results of operations and cash flows.

Also, under the Joint Stipulation, APCo's share of any net savings from the merger between AEP and CSW prior to December 31, 2004 shall be retained by APCo. As a result, all costs incurred in the merger that were allocated to APCo shall be fully charged to expense to partially offset merger savings through December 31, 2004 and shall not be included in any WV rate proceeding after that date. After December 31, 2004, current distribution savings related to the merger will be reflected in rates in any future rate proceeding before the WVPSC to establish distribution rates or to adjust rate caps during the transition to market based generation rates. When deregulation of generation occurs in WV, the net retained generation-related merger savings shall be used to recover any generation-related regulatory assets that are not recovered under the other provisions of the Joint Stipulation and the mechanisms provided for in the deregulation legislation and, to the extent possible, to recover any additional costs or obligations that deregulation may impose on APCo. Regardless of whether the net cumulative deferred ENEC overrecovery balance and the net merger savings are sufficient to offset all of APCo's generation-related regulatory assets, under the terms of the Joint Stipulation there will be no further explicit adjustment to APCo's rates to provide for recovery of generation-related regulatory assets beyond the above discussed specific adjustment provisions in the Joint Stipulation and the 0.5 mills per KWH wires charge in the WV Restructuring Plan (see Note 7 "Industry Restructuring" for discussion of WV Restructuring Plan). On June 2, 2000, the WVPSC issued an order approving the Joint Stipulation. Management expects that the stipulation agreement plus the provisions of pending restructuring legislation will, if the legislation becomes effective, provide for the recovery of existing regulatory assets, other stranded costs and the cost of such deregulation in WV.

**6. Effects of Regulation:**

In accordance with SFAS 71 the consolidated financial statements include regulatory assets (deferred expenses) and regulatory liabilities (deferred revenues) recorded in accordance with regulatory actions in order to match expenses and revenues from cost-based rates in the same accounting period. Regulatory assets are expected to be recovered in future periods through the rate-making process and regulatory liabilities are expected to reduce future cost recoveries. Among other things, application of SFAS 71 requires that the AEP System's regulated rates be cost-based and the recovery of regulatory assets probable. Management has reviewed all the evidence currently available and concluded that the requirements to apply SFAS 71 continue to be met for all electric operations in Indiana, Kentucky, Louisiana, Michigan, Oklahoma and Tennessee.

When the generation portion of the business in Arkansas, Ohio, Texas, Virginia and WV no longer met the requirements to apply SFAS 71, net regulatory assets were written off for that portion of the business unless they were determined to be recoverable as a stranded cost through regulated distribution rates or wire charges in accordance with SFAS 101 "Regulated Enterprises – Accounting for the Discontinuation of FASB Statement No. 71" and EITF 97-4 "Deregulation of the Pricing of Electricity – Issues Related to the Application of FASB No. 71, Accounting for the Effects of Certain Types of Regulation, and No. 101, Regulated Enterprises – Accounting for the Discontinuation of the Application of FASB Statement No. 71." In the Ohio, Virginia and WV jurisdictions the generation-related regulated assets that are recoverable through transition rates have been transferred to the distribution portion of the business and are being amortized as they are recovered through charges to regulated distribution customers. In the Texas jurisdiction generation-related regulatory assets that have been tentatively approved for recovery through securitization have been classified as "regulatory assets designated for securitization." (See Note 7 "Industry Restructuring" for further details.)

AEP's recognized regulatory assets and liabilities are comprised of the following at:

| | December 31, 2000 | December 31, 1999 |
|---|---|---|
| | (in millions) | |
| Regulatory Assets: | | |
| Amounts Due From Customers For Future Income Taxes | $ 914 | $1,450 |
| Transition - Regulatory Assets | 963 | - |
| Regulatory Assets Designated for Securitization | 953 | 953 |
| Deferred Fuel Costs | 407 | 477 |
| Unamortized Loss on Reacquired Debt | 113 | 154 |
| Cook Plant Restart Costs | 120 | 160 |
| DOE Decontamination and Decommissioning Assessment | 35 | 39 |
| Other | 193 | 231 |
| Total Regulatory Assets | $3,698 | $3,464 |
| Regulatory Liabilities: | | |
| Deferred Investment Tax Credits | $528 | $580 |
| Other | 208 | 315 |
| Total Regulatory Liabilities | $736 | $895 |

The recognized regulatory assets and liabilities for the registrant subsidiaries are comprised of the following at:

| December 31, 2000 | AEGCo | APCo | CPL | CSPCo | I&M |
|---|---|---|---|---|---|
| | | | (in thousands) | | |
| Regulatory Assets: | | | | | |
| Amounts Due From Customers For Future Income Taxes | | $217,540 | $ 206,930 | $ 31,853 | $229,466 |
| Transition - Regulatory Assets | | 191,469 | | 247,852 | |
| Excess Earnings | | | (39,700) | | |
| Regulatory Assets Designated For Securitization | | | 953,249 | | |
| Deferred Fuel Costs | | 14,669 | 127,295 | | 112,503 |
| Unamortized Loss on Reacquired Debt | $5,504 | 11,676 | 12,773 | 8,340 | 17,740 |
| Deferred Storm Damage | | 1,244 | | | |
| Cook Plant Restart Costs | | | | | 120,000 |
| DOE Decontamination and Decommissioning Assessment | | | 3,622 | | 31,744 |
| Other | | 11,152 | 18,815 | 3,508 | 40,687 |
| Total Regulatory Assets | $5,504 | $447,750 | $1,282,984 | $291,553 | $552,140 |
| Regulatory Liabilities: | | | | | |
| Deferred Investment Tax Credits | $59,718 | $ 43,093 | $128,100 | $41,234 | $113,773 |
| Amounts Due To Customers For Future Income Taxes | 23,996 | | | | |
| WV Rate Stabilization | | 75,601 | | | |
| Other | | 2,614 | | 11,510 | 9,930 |
| Total Regulatory Liabilities | $83,714 | $121,308 | $128,100 | $52,744 | $123,703 |

| December 31, 2000 | KPCo | OPCo | PSO | SWEPCo | WTU |
|---|---|---|---|---|---|
| | | | (in thousands) | | |
| Regulatory Assets: | | | | | |
| Amounts Due From Customers For Future Income Taxes | $85,926 | $180,602 | | $14,558 | |
| Transition - Regulatory Assets | | 517,851 | | | |
| Deferred Fuel Costs | | | $43,267 | 35,469 | $67,655 |
| Unamortized Loss on Reacquired Debt | 459 | 6,106 | 13,600 | 22,626 | 11,204 |
| Other | 12,130 | 10,151 | 15,738 | 19,898 | 13,604 |
| Total Regulatory Assets | $98,515 | $714,710 | $72,605 | $92,551 | $92,463 |
| Regulatory Liabilities: | | | | | |
| Deferred Investment Tax Credits | $11,656 | $25,214 | $35,783 | $53,167 | $24,052 |
| Excess Earnings | | | | 500 | 15,100 |
| Amounts Due To Customers For Future Income Taxes | | | 28,652 | | 13,493 |
| Other | 3,172 | 10,994 | 2,015 | 8,140 | |
| Total Regulatory Liabilities | $14,828 | $36,208 | $66,450 | $61,807 | $52,645 |

| December 31, 1999 | AEGCo | APCo | CPL | CSPCo | I&M |
|---|---|---|---|---|---|
| | | | (in thousands) | | |
| Regulatory Assets: | | | | | |
| Amounts Due From Customers For Future Income Taxes | | $389,922 | $212,364 | $243,031 | $236,783 |
| Excess Earnings | | | (18,400) | | |
| Regulatory Assets - Designated For Securitization | | | 953,249 | | |
| Deferred Fuel Costs | | | 30,423 | | 150,004 |
| Unamortized Loss on Reacquired Debt | $5,744 | 20,828 | 13,983 | 23,307 | 14,780 |
| Deferred Zimmer Plant Carrying Charges | | | | 42,826 | |
| Deferred Storm Damage | | 6,619 | | | |
| Cook Plant Restart Costs | | | | | 160,000 |
| DOE Decontamination and Decommissioning Assessment | | | 4,022 | | 35,238 |
| Other | | 19,525 | 11,390 | 29,939 | 28,005 |
| Total Regulatory Assets | $5,744 | $436,894 | $1,207,031 | $339,103 | $624,810 |
| Regulatory Liabilities: | | | | | |
| Deferred Investment Tax Credits | $63,114 | $ 57,259 | $ 133,306 | $ 44,716 | $121,627 |
| Amounts Due To Customers For Future Income Taxes | 26,266 | | | | |
| 50% Share - Net WV ENEC | | 36,589 | | | |
| Over Recovery - Fuel Costs | | 34,676 | | | |
| Deferred Gains From Emission Allowance Sales | | 1,867 | | 13,539 | |
| Other | | 7,180 | | 24,082 | 17,238 |
| Total Regulatory Liabilities | $89,380 | $137,571 | $ 133,306 | $ 82,337 | $138,865 |

| December 31, 1999 | KPCo | OPCo | PSO | SWEPCo | WTU |
|---|---|---|---|---|---|
| | | | (in thousands) | | |
| Regulatory Assets: | | | | | |
| Amounts Due From Customers For Future Income Taxes | $88,764 | $331,164 | | $ 7,128 | |
| Deferred Fuel Costs | | 197,631 | $6,469 | | $14,652 |
| Unamortized Loss on Reacquired Debt | 711 | 15,666 | 14,880 | 25,539 | 14,700 |
| Other | 6,821 | 49,924 | 1,837 | 14,513 | 15,045 |
| Total Regulatory Assets | $96,296 | $594,385 | $23,186 | $47,180 | $44,397 |
| Regulatory Liabilities: | | | | | |
| Deferred Investment Tax Credits | $12,908 | $ 35,838 | $37,574 | $57,649 | $25,323 |
| Excess Earnings | | | | 6,500 | 6,000 |
| Amounts Due To Customers For Future Income Taxes | | | 32,826 | | 13,146 |
| Deferred Gains From Emission Allowance Sales | | 53,738 | | | |
| Other | 2,792 | 13,043 | | 2,480 | |
| Total Regulatory Liabilities | $15,700 | $102,619 | $70,400 | $66,629 | $44,469 |

## 7. Industry Restructuring:

Restructuring legislation has been enacted in seven of the eleven state retail jurisdictions in which AEP's domestic electric utility companies operate. The legislation provides for a transition from cost-based regulation of bundled electric service to unbundled cost-based rate regulation of transmission and distribution service and customer choice market pricing for the supply of electricity. The enactment of restructuring legislation and the ability to determine transition rates, wires charges and any resultant extraordinary gain or loss under restructuring legislation enabled APCo, CPL, CSPCo, OPCo, SWEPCo and WTU to discontinue regulatory accounting for the generation portion of their business in those jurisdictions. Prior to restructuring, the electric utility companies accounted for their operations according to the cost-based regulatory accounting principles of SFAS 71. Under the provisions of SFAS 71, regulatory assets and regulatory liabilities are recorded to reflect the economic effects of regulation to account for the difference between regulatory accounting and GAAP and to match expenses with regulated revenues. The discontinuance of the application of SFAS 71 is in accordance with the provisions of SFAS 101. Pursuant to those provisions and further guidance provided in EITF Issue 97-4, a company is required to write-off regulatory assets and liabilities related to the deregulated operations, unless recovery of such amounts is provided through cost-based regulated rates to be collected in the portion of operations which continues to be rate regulated. Additionally, a company experiencing a discontinuance of cost-based rate regulation is required to determine if any plant assets are impaired under SFAS 121. A SFAS 121 accounting impairment analysis involves estimating cumulative future non-discounted net cash flows arising from the use of assets. If the cumulative undiscounted net cash flows exceed the net book value of the assets, then there is no impairment of the assets for accounting purposes. If there is any accounting impairment, it would be recorded on a discounted basis.

As legislative and regulatory proceedings evolve, the electric operating companies doing business in the seven states that have passed restructuring legislation are applying the standards discussed above to discontinue SFAS 71 regulatory accounting. The following is a summary of the restructuring legislation, the status of the transition plans and the status of the electric utility operating companies' accounting to comply with the changes in each of the seven state regulatory jurisdictions affected by restructuring legislation.

*Ohio Restructuring – Affecting AEP, CSPCo and OPCo*

Effective January 1, 2001, customer choice of electricity supplier began under the Ohio Act. In February 2001, one supplier announced its plan to offer service to CSPCo's residential customers. Currently for residential customers of OPCo, no alternative suppliers have registered with the PUCO as required by the Ohio Act. Two alternative suppliers have been approved to compete for CSPCo's and OPCo's commercial and industrial customers. Presently, customers continue to be served by CSPCo and OPCo with a legislatively required residential rate reduction of 5% for the generation portion of rates and a freezing of generation rates including fuel rates starting on January 1, 2001.

The Ohio Act provides for a five-year transition period to move from cost based rates to market pricing for generation services. It granted the PUCO broad oversight responsibility for promulgation of rules for competitive retail electric generation service, approval of a transition plan for each electric utility company and addressing certain major transition issues including unbundling of rates and the recovery of stranded costs including regulatory assets and transition costs.

The Ohio Act also provides for a reduction in property tax assessments, the imposition of replacement franchise and income taxes, and the replacement of a gross receipts tax with a KWH based excise tax. The property tax assessment percentage on generation property was lowered from 100% to 25% of value effective January 1, 2001 and Ohio electric utilities will become subject to the Ohio Corporate Franchise Tax and municipal income taxes on January 1, 2002. The last year for which Ohio electric utilities will pay the excise tax based on gross receipts is the tax year ending April 30, 2002. As of May 1, 2001 electric distribution companies will be subject to an excise tax based on KWH sold to Ohio customers. The gross receipts tax is paid at the beginning of the tax year (May 1), deferred by CSPCo and OPCo as a prepaid expense and amortized to expense during the tax year pursuant to the tax law whereby the payment of the tax results in the privilege to conduct business in the year following the payment of the tax. As a result a duplicate tax will be expensed from May 1, 2001 through April 30, 2002 adding approximately $90 million ($40 million for CSPCo and $50 million for OPCo) to tax expense during that period. Unless CSPCo and OPCo can recover the duplicate amount from ratepayers it will negatively impact results of operations.

On September 28, 2000, the PUCO approved, with minor modifications, a stipulation agreement between CSPCo, OPCo, the PUCO staff, the Ohio Consumers' Counsel and other concerned parties regarding transition plans filed by CSPCo and OPCo. The key provisions of this stipulation agreement are:

- Recovery of generation-related regulatory assets at December 31, 2000 over seven years for OPCo ($518 million) and over eight years for CSPCo ($248 million) through frozen transition rates for the first five years of the recovery period and a wires charge for the remaining years.
- A shopping incentive (a price credit) of 2.5 mills per KWH for the first 25% of CSPCo residential customers that switch suppliers. There is no shopping incentive for OPCo customers.
- The absorption of $40 million by CSPCo and OPCo ($20 million per company) of consumer education, implementation and transition plan filing costs with deferral of the remaining costs, plus a carrying charge, as a regulatory asset for recovery in future distribution rates.
- CSPCo and OPCo will make available a fund of up to $10 million to reimburse customers who choose to purchase their power from another company for certain transmission charges imposed by PJM and/or a Midwest ISO on generation originating in the Midwest ISO or PJM areas.
- The statutory 5% reduction in the generation component of residential tariffs will remain in effect for the entire five year transition period.
- CSPCo's and OPCo's request for a $90 million gross receipts tax rider to recover the duplicate gross receipts KWH based excise tax would be considered separately by the PUCO.

The approved stipulation agreement also accepted the following provisions contained in CSPCo's and OPCo's filed transition plans:

- a corporate separation plan to segregate generation, transmission and distribution assets into separate legal entities, and
- a plan for independent operation of transmission facilities.

The gross receipts tax issue was considered by the PUCO in hearings held in June 2000. In the September 28, 2000 order approving the stipulation agreement, the PUCO determined that there was no duplicate tax overlap period and denied the request for a $90 million gross receipts tax rider. CSPCo's and OPCo's request for rehearing of the gross receipts tax issue was denied. An appeal of this issue to the Ohio Supreme Court has been filed. Unless this issue is resolved in CSPCo's and OPCo's favor, it will have an adverse effect on future results of operations and financial position.

One of the intervenors at the hearings for approval of the settlement agreement (whose request for rehearing was denied by the PUCO) has filed with the Ohio Supreme Court for review of the settlement agreement including recovery of regulatory assets. Management is unable to predict the outcome of litigation but the resolution of this matter could negatively impact results of operation.

Beginning January 1, 2001, CSPCo's and OPCo's fuel costs will not be subject to PUCO fuel recovery proceedings. Deferred fuel costs at December 31, 2000 which represent under or over recoveries were one of the items included in the PUCO's final determination of net regulatory assets to be collected (recovered) during the transition period. The elimination of fuel clause recoveries in 2001 in Ohio will subject AEP, CSPCo and OPCo to the risk of fuel market price increases and could adversely affect their future results of operations and cash flows.

*CSPCo and OPCo Discontinue Application of SFAS 71 Regulatory Accounting for the Ohio Jurisdiction*

In September 2000 CSPCo and OPCo discontinued the application of SFAS 71 for their Ohio retail jurisdictional generation business since generation is no longer cost-based regulated in the Ohio jurisdiction and management was able to determine their transition rates and wires charges. The discontinuance in the Ohio jurisdiction was possible as a result of the PUCO's September 28, 2000 approval of the stipulation agreement which established rates, wires charges and net regulatory asset recovery procedures during the transition to market rates.

CSPCo's and OPCo's discontinuance of SFAS 71 for generation resulted in after tax extraordinary losses in the third quarter of 2000 of $25 million and $19 million, respectively, due to certain unrecoverable generation-related regulatory assets and transition expenses. Management believes that substantially all of the remaining net regulatory assets related to the Ohio generation business will be recovered under the PUCO's September 28, 2000 order. Therefore, under the provisions of EITF 97-4, CSPCo's and OPCo's generation-related recoverable net regulatory assets were transferred to the transmission and distribution portion of the business and will be amortized as they are recovered through transition rates to customers. CSPCo and OPCo performed an accounting impairment analysis on their generating assets under SFAS 121 as required when discontinuing the application of SFAS 71 and concluded there was no impairment of generation assets.

*Virginia – Affecting AEP and APCo*

In Virginia, a restructuring law provides for a transition to choice of electricity supplier for retail customers beginning on January 1, 2002. In February 2001 restructuring revision legislation was approved by the Virginia Legislature which could modify the terms of restructuring. Presently, the transition period is to be completed, subject to a finding by the Virginia SCC that an effective competitive market exists by January 1, 2004 but no later than January 1, 2005.

The restructuring law also provides an opportunity for recovery of just and reasonable net stranded generation costs. The mechanisms in the Virginia law for net stranded cost recovery are: a capping of rates until as late as July 1, 2007, and the application of a wires charge upon customers who depart the incumbent utility in favor of an alternative supplier prior to the termination of the rate cap. The restructuring law provides for the establishment of capped rates prior to January 1, 2001 based either on a request by APCo for a change in rates prior to January 1, 2001 or on the rates in effect at July 1, 1999 if no rate change request is made and the establishment of a wires charge by the fourth quarter of 2001. APCo did not request new rates; therefore, its current rates are the capped rates. In the third quarter of 2000, the Virginia SCC directed APCo to file a cost of service study using 1999 as a test year to review the reasonableness of APCo's capped rates. The cost of service study was filed on January 3, 2001. In the opinion of APCo's Virginia counsel, Virginia's restructuring law does not permit the Virginia SCC to change rates for the transition period except for changes in the fuel factor, changes in state gross receipts taxes, or to address the utility's financial distress. However, if the Virginia SCC were to reduce APCo's capped rates or deny recovery of regulatory assets, it would adversely affect results of operations if such action is ultimately determined to be legal.

The Virginia restructuring law also requires filings to be made that outline the functional separation of generation from transmission and distribution and a rate unbundling plan. On January 3, 2001, APCo filed its corporate separation plan and rate unbundling plan with the Virginia SCC which is based on the most recent rate case test year (1996). See the heading "Structural Separation" below in this footnote for a discussion of AEP's corporate separation plan filed with the SEC.

*West Virginia – Affecting AEP and APCo*

On January 28, 2000, the WVPSC issued an order approving an electricity restructuring plan for WV. On March 11, 2000, the WV Legislature approved the restructuring plan by joint resolution. The joint resolution provides that the WVPSC cannot implement the plan until the legislature makes necessary tax law changes to preserve the revenues of the state and local governments. The Joint Committee on Government and Finance of the WV Legislature hired a consultant to study and issue a report on the tax changes required to implement electric restructuring. Moreover, the committee also hired a consultant to study and issue a report on the electric restructuring plan in light of events occurring in California. The WV Legislature is not expected to consider these reports until the 2002 Legislative Session since the 2001 Legislative Session ends in April 2001. Since the WV Legislature has not yet passed the required tax law changes, the restructuring plan has not become effective. AEP subsidiaries, APCo and WPCo, provide electric service in WV.

The provisions of the restructuring plan provide for customer choice to begin after all necessary rules are in place (the "starting date"); deregulation of generation assets on the starting date; functional separation of the generation, transmission and distribution businesses on the starting date and their legal corporate separation no later than January 1, 2005; a transition period of up to 13 years, during which the incumbent utility must provide default service for customers who do not change suppliers unless an alternative default supplier is selected through a WVPSC-sponsored bidding process; capped and fixed rates for the 13 year transition period as discussed below; deregulation of metering and billing; a 0.5 mills per KWH wires charge applicable to all retail customers for a 10-year period commencing with the starting date intended to provide for recovery of any stranded cost including net regulatory assets; establishment of a rate stabilization deferred liability balance of $81 million ($76 million by APCo and $5 million by WPCo) by the end of year ten of the transition period to be used as determined by the WVPSC to offset market prices paid in the eleventh, twelfth, and thirteenth year of the transition period by residential and small commercial customers that do not choose an alternative supplier.

Default rates for residential and small commercial customers are capped for four years after the starting date and then increase as specified in the plan for the next six years. In years eleven, twelve and thirteen of the transition period, the power supply rate shall equal the market price of comparable power. Default rates for industrial and large commercial customers are discounted by 1% for four and a half years, beginning July 1, 2000, and then increased at pre-defined levels for the next three years. After seven years the power supply rate for industrial and large commercial customers will be market based. APCo's Joint Stipulation agreement, discussed in Note 5 "Rate Matters", which was approved by the WVPSC on June 2, 2000 in connection with a base rate filing, also provides additional mechanisms to recover regulatory assets.

*APCo Discontinues Application of SFAS 71 Regulatory Accounting*

In June 2000 APCo discontinued the application of SFAS 71 for its Virginia and WV retail jurisdictional portions of its generation business since generation is no longer considered to be cost-based regulated in those jurisdictions and management was able to determine APCo's transition rates and wires charges. The discontinuance in the WV jurisdiction was made possible by the June 2, 2000 approval of the Joint Stipulation which established rates, wires charges and regulatory asset recovery procedures for the transition period to market rates which was determined to be probable. APCo was also able to discontinue application of SFAS 71 for the generation portion of its Virginia retail jurisdiction after management decided that APCo would not request capped rates different from its current rates. The existence of effective restructuring legislation in Virginia and the probability that the WV legislation would become effective with the expected probable passage of required enabling tax legislation in 2001 supported management's decision in 2000 to discontinue SFAS 71 regulatory accounting for APCo's electricity generation and supply business.

APCo's discontinuance of SFAS 71 for generation resulted in an after tax extraordinary gain, in the second quarter of 2000, of $9 million. Management believes that it is probable that substantially all net regulatory assets related to the Virginia and WV generation business will be recovered. Therefore, under the provisions of EITF 97-4, APCo's generation-related net regulatory assets were transferred to the distribution portion of the business and are being amortized as they are recovered through charges to regulated distribution customers. As required by SFAS 101 when discontinuing SFAS 71 regulatory accounting, APCo performed an accounting impairment analysis on its generating assets under SFAS 121 and concluded that there was no accounting impairment of generation assets.

The studies requested by the WV Legislature, discussed above, could result in the WV Legislature deciding not to enact the required tax changes, thereby, effectively continuing cost based rate regulation in West Virginia or it could modify the restructuring plan. Modifications in the restructuring plan could adversely affect future results of operations if they were to occur. Management is carefully monitoring the situation in West Virginia and continues to work with all concerned parties to get approval to successfully transition APCo's generation business in West Virginia. Failure to pass the required enabling tax changes could ultimately require APCo to reinstate regulatory accounting principles under SFAS 71 for its generation operations in West Virginia.

*Arkansas Restructuring – Affecting AEP and SWEPCo*

In 1999 legislation was enacted in Arkansas that will ultimately restructure the electric utility industry. Its major provisions are:

- retail competition begins January 1, 2002 but can be delayed until as late as June 30, 2003 by the Arkansas Commission;
- transmission facilities must be operated by an ISO if owned by a company which also owns generation assets;
- rates will be frozen for one to three years;
- market power issues will be addressed by the Arkansas Commission; and
- an annual progress report to the Arkansas General Assembly on the development of competition in electric markets and its impact on retail customers is required.

In November 2000 the Arkansas Commission filed its annual progress report with the Arkansas General Assembly recommending a delay in the start date of retail competition to a date between October 1, 2003 and October 1, 2005. The report also asks the Arkansas General Assembly to delegate authority to the Arkansas Commission to determine the appropriate retail competition start date within the approved time frame. In February 2001 the Arkansas General Assembly passed legislation that was signed into law by the Governor that changes the date of electric retail competition to October 1, 2003, and provided the Arkansas Commission with the authority to delay that date for up to two years.

*Texas Restructuring – Affecting AEP, CPL, SWEPCo and WTU*

In June 1999 Texas restructuring legislation was signed into law which, among other things:

- gives Texas customers of investor-owned utilities the opportunity to choose their electricity provider beginning January 1, 2002;
- provides for the recovery of regulatory assets and of other stranded costs through securitization and non-bypassable wires charges;
- requires reductions in NOx and sulfur dioxide emissions;
- provides for a rate freeze until January 1, 2002 followed by a 6% rate reduction for residential and small commercial customers and a number of customer protections;

- provides for an earnings test for each of the three years of the rate freeze period (1999 through 2001) which will reduce stranded cost recoveries or if there is no stranded cost provides for a refund or their use to fund certain capital expenditures in the amount of the excess earnings;
- requires each utility to structurally unbundle into a retail electric provider, a power generation company and a transmission and distribution utility;
- provides for certain limits for ownership and control of generating capacity by companies;
- provides for elimination of the fuel clause reconciliation process beginning January 1, 2002; and
- provides for a 2004 true-up proceeding to determine recovery of stranded costs including final fuel recovery balances, net regulatory assets, certain environmental costs, accumulated excess earnings and other issues.

Under the Texas Legislation, delivery of electricity will continue to be the responsibility of the local electric transmission and distribution utility company at regulated prices. Each electric utility was required to submit a plan to structurally unbundle its business activities into a retail electric provider, a power generation company, and a transmission and distribution utility. In May 2000 CPL, SWEPCo and WTU filed a revised business separation plan that the PUCT approved on July 7, 2000 in an interim order. The revised business separation plans provided for CPL and WTU, which operate in Texas only, to establish separate companies and divide their integrated utility operations and assets into a power generation company, a transmission and distribution utility and a retail electric provider. SWEPCo will separate its Texas jurisdictional transmission and distribution assets and operations into a new Texas regulated transmission and distribution subsidiary. In addition, a retail electric provider will be formed by SWEPCo to provide retail electric service to SWEPCo's Texas jurisdictional customers.

Under the Texas Legislation, electric utilities are allowed, with the approval of the PUCT, to recover stranded generation costs including generation-related regulatory assets that may not be recoverable in a future competitive market. The approved stranded costs can be refinanced through securitization, which is a financing structure designed to provide lower financing costs than are available through conventional financings. Lower financing costs are achieved through the issuance of securitization bonds at a lower interest rate to finance 100% of the costs pursuant to a state pledge to ensure recovery of the bond principal and financing costs through a non-bypassable rate surcharge by the regulated transmission and distribution utility over the life of the securitization bonds.

In 1999 CPL filed an application with the PUCT to securitize approximately $1.27 billion of its retail generation-related regulatory assets and approximately $47 million in other qualified restructuring costs. On March 27, 2000, the PUCT issued an order permitting CPL to securitize approximately $764 million of net regulatory assets. The PUCT's order authorized issuance of up to $797 million of securitization bonds including the $764 million for recovery of net generation-related regulatory assets and $33 million for other qualified refinancing costs. The $764 million for recovery of net generation-related regulatory assets reflects the recovery of $949 million of generation-related regulatory assets offset by $185 million of customer benefits associated with accumulated deferred income taxes. CPL had previously proposed in its filing to flow these benefits back to customers over the 14-year term of the securitization bonds. On April 11, 2000, four parties appealed the PUCT's securitization order to the Travis County District Court. In July 2000 the Travis County District Court upheld the PUCT's securitization order. The securitization order is being appealed to the Supreme Court of Texas. One of these appeals challenges CPL's ability to recover securitization charges under the Texas Constitution. CPL will not be able to issue the securitization bonds until these appeals are resolved.

The remaining regulatory assets of $206 million originally included by CPL in its 1999 securitization request were included in a March

2000 filing with the PUCT, requesting recovery of an additional $1.1 billion of stranded costs. The March 2000 filing of $1.1 billion included recovery of approximately $800 million of STP costs included in property, plant and equipment-electric on AEP's Consolidated Balance Sheets and in electric utility plant-production on CPL's Consolidated Balance Sheets. These STP costs had previously been identified as excess cost over market (ECOM) by the PUCT for regulatory purposes and were earning a lower return and were being amortized on an accelerated basis for rate-making purposes in Texas. The March 2000 filing will determine the initial amount of stranded costs in addition to the securitized regulatory assets to be recovered beginning January 1, 2002.

CPL submitted a revised estimate of stranded costs on October 2, 2000 using assumptions developed in generic proceedings by the PUCT and an administrative model developed by the PUCT staff that reduced the amount of the initial stranded cost estimate to $361 million from the $1.1 billion requested by CPL. CPL subsequently agreed to accept adjustments proposed by intervenors that reduced ECOM to approximately $230 million. Hearings on CPL's requested ECOM were held in October 2000. In February 2001 the PUCT issued an interim decision determining an initial amount of CPL ECOM or stranded costs of negative $580 million. The decision indicated that CPL's costs were below market after securitization of regulatory assets. Management does not agree with the critical inputs to this model. Management believes CPL has a positive stranded cost exclusive of securitized regulatory assets. The final amount of CPL's stranded costs including regulatory assets and ECOM will be established by the PUCT in the legislatively required 2004 true-up proceeding. If CPL's total stranded costs determined in the 2004 true-up are less than the amount of securitized regulatory assets, the PUCT can implement an offsetting credit to transmission and distribution rates.

The PUCT ruled that prior to the 2004 true-up proceeding, no adjustments would be made to the amount of regulatory costs authorized by the PUCT to be securitized. However, the PUCT also ruled that excess earnings for the period 1999-2001 should be refunded through transmission and distribution rates to the extent of any over-mitigation of stranded costs represented by negative ECOM. In the event that CPL will be required to refund excess earnings in the future instead of applying them to reduce ECOM or regulatory assets, it will adversely affect future cash flow but not results of operations since excess earnings for 1999 and 2000 were accrued and expensed in 1999 and 2000. The Texas Legislation allows for several alternative methods to be used to value stranded costs in the final 2004 true-up proceeding including the sale or exchange of generation assets, the issuance of power generation company stock to the public or the use of PUCT staff's ECOM model. To the extent that the final 2004 true-up proceeding determines that CPL should recover additional stranded costs, the total amount recoverable can be securitized.

The Texas Legislation provides that each year during the 1999 through 2001 rate freeze period, electric utilities are subject to an earnings test. For electric utilities with stranded costs, such as CPL, any earnings in excess of the most recently approved cost of capital in its last rate case must be applied to reduce stranded costs. Utilities without stranded costs, such as SWEPCo and WTU, must either flow such excess earnings amounts back to customers or make capital expenditures to improve transmission or distribution facilities or to improve air quality. The Texas Legislation requires PUCT approval of the annual earnings test calculation.

The 1999 earnings test reports filed by CPL, SWEPCo and WTU showed excess earnings of $21 million, $1 million and zero, respectively. The PUCT staff issued its report on the excess earnings calculations filed by CPL, SWEPCo and WTU and calculated the excess earnings amounts to be $41 million, $3 million and $11 million for CPL, SWEPCo and WTU, respectively. The Office of Public Utility Counsel also filed exceptions to the companies' earnings reports. Several issues were resolved via settlement and the remaining open issues were submitted to the

PUCT. A final order was issued by the PUCT in February 2001 and adjustments to the accrued 1999 and 2000 excess earnings were recorded in results of operations in the fourth quarter of 2000. After adjustments the accruals for 1999 excess earnings for CPL and WTU were $24 million and $1 million, respectively. CPL and WTU also recorded an estimated provision for excess 2000 earnings of $16 million and $14 million, respectively.

A Texas settlement agreement in connection with the AEP and CSW merger permits CPL to apply for regulatory purposes up to $20 million of STP ECOM plant assets a year in 2000 and 2001 to reduce excess earnings, if any. For book and financial reporting purposes, STP ECOM plant assets will be depreciated in accordance with GAAP, on a systematic and rational basis unless impaired. CPL will establish a regulatory liability or reduce regulatory assets by a charge to earnings to the extent excess earnings exceed $20 million in 2000 and 2001.

Beginning January 1, 2002, fuel costs will not be subject to PUCT fuel reconciliation proceedings. Consequently, CPL, SWEPCo and WTU will file a final fuel reconciliation with the PUCT to reconcile their fuel costs through the period ending December 31, 2001. Fuel costs have been reconciled by CPL, SWEPCo and WTU through June 30, 1998, December 31, 1999 and June 30, 1997, respectively. WTU is currently reconciling its fuel through June 2000. See discussion in Note 5 "Rate Matters". At December 31, 2000, CPL's, SWEPCo's and WTU's Texas jurisdictional unrecovered deferred fuel balances were $127 million, $20 million and $59 million, respectively. Final unrecovered deferred fuel balances at December 31, 2001 will be included in each company's 2004 true-up proceeding. If the final fuel balances or any amount incurred but not yet reconciled were not recovered, they could have a negative impact on results of operations. The elimination of the fuel clause recoveries in 2002 in Texas will subject AEP, CPL, SWEPCo and WTU to greater risks of fuel market price increases and could adversely affect future results of operations beginning in 2002.

The affiliated retail electric provider of CPL, SWEPCo and WTU will be required to offer residential and small commercial customers (with a peak usage of less than 1000 KW) a rate 6% below rates in effect on January 1, 1999 adjusted for any changes in fuel cost recovery factors since January 1, 1999 (price to beat). The price to beat must be offered to residential and small commercial customers until January 1, 2007. Customers with a peak usage of more than 1000 KW are subject to market rates. The Texas restructuring legislation provides for the price to beat to be adjusted up to two times annually to reflect significant changes in fuel and purchased energy costs.

*Discontinuance of the Application of SFAS 71 Regulatory Accounting in Arkansas and Texas*

The financial statements of CPL, SWEPCo and WTU have historically reflected the economic effects of regulation by applying the requirements of SFAS 71. As a result of the scheduled deregulation of generation in Arkansas and Texas, the application of SFAS 71 for the generation portion of the business in those states was discontinued in the third quarter of 1999. Under the provisions of EITF 97-4, CPL's generation-related net regulatory assets were transferred to the distribution portion of the business and will be amortized as they are recovered through wires charges to customers. Management believes that substantially all of CPL's generation-related regulatory assets will be recovered under the Texas Legislation. CPL's recovery of generation-related regulatory assets and stranded costs are subject to a final determination by the PUCT in 2004. If future events were to make the recovery through securitization of CPL's generation-related regulatory assets no longer probable, CPL would write-off the portion of such regulatory assets deemed unrecoverable as a non-cash extraordinary charge to earnings.

The Texas Legislation provides that all finally determined stranded costs will be recovered. Since SWEPCo and WTU are not expected to have net stranded costs, all Arkansas and Texas jurisdictional generation-related net regulatory assets were written off as non-recoverable in 1999 when SWEPCo and WTU discontinued the application of SFAS 71 regulatory accounting. As required by SFAS 101 when SFAS 71 is discontinued, an accounting impairment analysis for generation assets under SFAS 121 was completed for CPL, SWEPCo and WTU. The analysis showed that there was no accounting impairment of generation assets when the application of SFAS 71 was discontinued. CPL, SWEPCo and WTU will test their generation assets for impairment under SFAS 121 if circumstances change. Management believes that on a discounted basis CPL's generation business net cash flows will likely be less than its generating assets' net book value and together with its generation-related regulatory assets should create a recoverable stranded cost for regulatory purposes under the Texas Legislation. Therefore, management continues to carry on the balance sheet at December 31, 2000, $953 million of generation-related regulatory assets already approved for securitization and $195 million of net generation-related regulatory assets pending approval for securitization in Texas. A final determination of whether they will be securitized and recovered will be made as part of the 2004 true-up proceeding.

CPL, SWEPCo, and WTU continue to analyze the impact of electric utility industry restructuring legislation on their Arkansas and Texas electric operations. Although management believes that the Texas Legislation provides for full recovery of stranded costs and that the companies do not have a recordable accounting impairment, a final determination of whether CPL will experience an accounting loss or whether SWEPCo and WTU will experience any additional accounting loss from an inability to recover generation-related regulatory assets and other restructuring related costs in Texas and Arkansas cannot be made until such time as the regulatory process is complete following the 2004 true-up proceeding in Texas and a determination by the Arkansas Commission. In the event CPL, SWEPCo, and WTU are unable after the 2004 true-up proceeding and after the Arkansas Commission proceedings to recover all or a portion of their generation-related regulatory assets, stranded costs and other restructuring related costs, it could have a material adverse effect on results of operations, cash flows and possibly financial condition.

Although Arkansas' delay of retail competition may be having a negative effect on the progress of efforts to transition SWEPCo's generation in Arkansas to market based pricing of electricity, it appears that Texas is moving forward as planned. Management is carefully monitoring the situation in Arkansas and is working with all concerned parties to prudently quicken the pace of the transition. However, changes could occur due to concerns stemming from the California energy crisis and other events which could adversely affect future results of operations in Arkansas and possibly Texas.

*Michigan Restructuring - Affecting AEP and I&M*

On June 5, 2000, the Michigan Legislation became law. Its major provisions, which were effective immediately, applied only to electric utilities with one million or more retail customers. I&M, AEP's electric operating subsidiary doing business in Michigan, has less than one million customers in Michigan. Consequently, I&M was not immediately required to comply with the Michigan Legislation.

The Michigan Legislation gives the MPSC broad power to issue orders to implement retail customer choice of electric supplier no later than January 1, 2002 including recovery of regulatory assets and stranded costs. On October 2, 2000, I&M filed a restructuring implementation plan as required by a MPSC order. The plan identifies I&M's proposal to file with the MPSC on June 5, 2001 its unbundled rates, open access tariffs, terms of service and supporting schedules. Described in the plan are I&M's intentions and preparation for competition related to supplier transactions, customer transactions, rate unbundling, education programs, and regional transmission organization. The plan contains a proposed methodology to determine stranded costs and implementation costs and requests the continuation of a wires charge for recovery of nuclear decommissioning costs. Approval of the restructuring implementation plan is pending before the MPSC.

Management has concluded that as of December 31, 2000 the requirements to apply SFAS 71 continue to be met since I&M's rates for generation in Michigan will continue to be cost-based regulated until the MPSC approves rates and wires charges in 2001. The establishment of rates and wires charges under a MPSC approved transition plan will enable management to determine the ability to recover stranded costs including regulatory assets and other implementation costs, a requirement of EITF 97-4 to discontinue the application of SFAS 71.

Upon the discontinuance of SFAS 71, I&M will, if necessary, have to write off its Michigan jurisdictional generation-related regulatory assets and record its unrecorded Michigan jurisdictional liability for decommissioning the Cook Plant to the extent that they cannot be recovered under the transition rates and wires charges. As required by SFAS 101 when discontinuing SFAS 71 regulatory accounting, I&M will have to perform an accounting impairment analysis under SFAS 121 to determine if the Michigan jurisdictional portion of its generating assets are impaired for accounting purposes.

The amount of regulatory assets recorded on the books at December 31, 2000 applicable to I&M's Michigan retail jurisdictional generation business is approximately $45 million before related tax effects. The estimated unrecorded liability for the Michigan jurisdiction to decommission the Cook Plant ranges from $114 million to $215 million in 2000 non-discounted dollars based upon studies completed during 2000. For the Michigan jurisdiction, I&M has accumulated approximately $100 million in trust funds to decommission the Cook Plant. Based on the current information available, management does not anticipate that I&M will experience any material tangible asset accounting impairment or regulatory asset write-offs. Ultimately, however, whether I&M will experience material regulatory asset write-offs will depend on whether the MPSC approves their recovery in future restructuring proceedings.

A determination of whether I&M will experience any asset impairment loss regarding its Michigan retail jurisdictional generating assets and any loss from a possible inability to recover Michigan generation-related regulatory assets, decommissioning obligations and transition costs cannot be made until such time as the rates and the wires charges are determined through the regulatory process. In the event I&M is unable to recover all or a portion of its generation-related regulatory assets, unrecorded decommissioning obligation, stranded costs and other implementation costs, it could have a material adverse effect on results of operations, cash flows and possibly financial condition.

*Oklahoma Restructuring – Affecting AEP and PSO*

In 1997, the Oklahoma Legislature passed restructuring legislation providing for retail open access by July 1, 2002. That legislation called for a number of studies to be completed on a variety of restructuring issues, including an independent system operator, technical, financial, transition and consumer issues. During 1998 and 1999 several of the studies were completed.

The information from the studies was expected to be used in the development of additional industry restructuring legislation during the 2000 legislative session. Several additional electric industry restructuring bills were filed in the 2000 Oklahoma legislative session. The proposed bills generally supplemented the industry restructuring legislation previously enacted in Oklahoma which lacked specific procedures for a transition to market based competitive prices. The industry restructuring legislation previously passed did not delegate the establishment of transition procedures to the Oklahoma Corporation Commission. The 2000 Oklahoma legislative session adjourned in May without passing further restructuring legislation.

The 2001 Oklahoma legislative session convened in early February. No further electric restructuring legislation has passed and proposals have been made to delay the implementation of the transition to customer choice and market based pricing under the restructuring legislation. If the necessary legislation is not passed, PSO's generation and retail electric supply business will remain regulated in Oklahoma. If implementation legislation were to modify the original restructuring legislation in Oklahoma it could have a adverse effect on results of operations.

Management has concluded that as of December 31, 2000 the requirements to apply SFAS 71 continue to be met since PSO's rates for generation in Oklahoma will continue to be cost-based regulated until the Oklahoma Legislature approves further restructuring legislation and transition rates and wires charges are established under an approved transition plan. Until management is able to determine the ability to recover stranded costs which includes regulatory assets and other implementation costs, PSO cannot discontinue application of SFAS 71 accounting under GAAP.

When PSO discontinues application of SFAS 71, it will be necessary to write off Oklahoma jurisdictional generation-related regulatory assets to the extent that they cannot be recovered under the transition rates and wires charges, when determined, and record any asset accounting impairments in accordance with SFAS 121.

A determination of whether PSO will experience any asset impairment loss regarding its Oklahoma retail jurisdictional generating assets and any loss from a possible inability to recover Oklahoma generation-related regulatory assets and other transition costs cannot be made until such time as the rates and the wires charges are determined through the legislative and/or regulatory process. In the event PSO is unable to recover all or a portion of its generation-related regulatory assets and implementation costs, Oklahoma restructuring could have a material adverse effect on results of operations and cash flows.

*Structural Separation*

On November 1, 2000, AEP, AEPSC, APCo, CPL, CSPCo, OPCo, SWEPCo and WTU filed with the SEC for approval to form two separate legal holding company subsidiaries of AEP, the parent company. The purpose of these entities is to legally and functionally separate the competitive market business activities and the subsidiaries performing those competitive activities from the business activities which are cost-based regulated and the subsidiaries that perform those regulated activities. Corporate separation plans have also been filed with regulatory commissions in Arkansas, Ohio, Texas and Virginia to comply with requirements specified in their restructuring legislation. The Texas Legislation requires separate legal entities for generation and distribution assets by January 1, 2002. AEP, APCo, CPL, CSPCo, OPCo, SWEPCo and WTU will need approval from the SEC under PUHCA, FERC and certain state regulatory commissions to make these organization changes.

**8. Commitments and Contingencies:**

*Construction and Other Commitments* - The AEP System has substantial construction commitments to support its operations. Aggregate construction expenditures for 2001-2003 for consolidated domestic and foreign operations are estimated to be $7 billion.

The following table shows the estimated construction expenditures of the subsidiary registrants for 2001 – 2003:

| | (in millions) |
|---|---|
| AEGCo | $ 9.1 |
| APCo | 1,164.3 |
| CPL | 770.2 |
| CSPCo | 422.2 |
| I&M | 439.6 |
| KPCo | 215.6 |
| OPCo | 1,085.2 |
| PSO | 310.8 |
| SWEPCo | 413.1 |
| WTU | 259.3 |

Long-term contracts to acquire fuel for electric generation have been entered into for various terms, the longest of which extends to the year 2014 for the AEP System. The expiration date of the longest fuel contract for APCo is 2006, CSPCo is 2007, I&M is 2014, KPCo is 2003, OPCo is 2012, PSO is 2014, SWEPCo is 2006 and WTU is 2006. The contracts provide for periodic price adjustments and contain various clauses that would release the subsidiaries from their obligations under certain force majeure conditions.

The AEP System has contracted to sell approximately 1,174 MW of capacity domestically on a long-term basis to unaffiliated utilities. Certain of these contracts totaling 250 mw of capacity are unit power agreements requiring the delivery of energy only if the unit capacity is available. The power sales contracts expire from 2001 to 2010.

*Nuclear Plants – Affecting AEP, CPL and I&M*

I&M owns and operates the two-unit 2,110 MW Cook Plant under licenses granted by the NRC. CPL owns 25.2% of the two-unit 2,500 MW STP. STPNOC operates STP on behalf of the joint owners under licenses granted by the NRC. The operation of a nuclear facility involves special risks, potential liabilities, and specific regulatory and safety requirements. Should a nuclear incident occur at any nuclear power plant facility in the U.S., the resultant liability could be substantial. By agreement I&M and CPL are 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. In the event nuclear losses or liabilities are underinsured or exceed accumulated funds and recovery in rates is not possible, results of operations, cash flows and financial condition would be adversely affected.

*Nuclear Incident Liability – Affecting AEP, CPL and I&M*

The Price-Anderson Act establishes insurance protection for public liability arising from a nuclear incident at $9.5 billion and covers any incident at a licensed reactor in the U.S. Commercially available insurance provides $200 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 $88 million on each licensed reactor in the U.S. payable in annual installments of $10 million. As a result, I&M could be assessed $176 million per nuclear incident payable in annual installments of $20 million. CPL could be assessed $44 million per nuclear incident payable in annual installments of $5 million as its share of a STPNOC assessment. The number of incidents for which payments could be required is not limited.

Insurance coverage for property damage, decommissioning and decontamination at the Cook Plant and STP is carried by I&M and STPNOC in the amount of $1.8 billion each. Cook Plant and STPNOC jointly purchase $1 billion of excess coverage for property damage, decommissioning and decontamination. Additional insurance provides coverage for extra costs resulting from a prolonged accidental outage.

*SNF Disposal – Affecting AEP, CPL, and I&M*

Federal law provides for government responsibility for permanent SNF disposal and assesses nuclear plant owners fees for SNF disposal. A fee of one mill per KWH for fuel consumed after April 6, 1983 at Cook Plant and STP is being collected from customers and remitted to the U.S. Treasury. Fees and related interest of $211 million for fuel consumed prior to April 7, 1983 at Cook Plant have been recorded as long-term debt. I&M has not paid the government the Cook Plant related pre-April 1983 fees due to continued delays and uncertainties related to the federal disposal program. At December 31, 2000, funds collected from customers towards payment of the pre-April 1983 fee and related earnings thereon are in external funds and approximate the liability. CPL is not liable for any assessments for nuclear fuel consumed prior to April 7, 1983 since the STP units began operation in 1988 and 1989.

*Decommissioning and Low Level Waste Accumulation Disposal – Affecting AEP, CPL and I&M*

Decommissioning costs are accrued over the service lives of the Cook Plant and STP. The licenses to operate the two nuclear units at Cook Plant expire in 2014 and 2017. After expiration of the licenses, Cook Plant is expected to be decommissioned through dismantlement. The estimated cost of decommissioning and low level radioactive waste accumulation disposal costs for Cook Plant ranges from $783 million to $1,481 million in 2000 nondiscounted dollars. The wide range is caused by variables in assumptions including the estimated length of time SNF may need to be stored at the plant site subsequent to ceasing operations. This, in turn, depends on future developments in the federal government's SNF disposal program. Continued delays in the federal fuel disposal program can result in increased decommissioning costs. I&M is recovering estimated Cook Plant decommissioning costs in its three rate-making jurisdictions based on at least the lower end of the range in the most recent decommissioning study at the time of the last rate proceeding. The amount recovered in rates for decommissioning the Cook Plant and deposited in the external fund was $28 million in 2000, $28 million in 1999 and $29 million in 1998.

The licenses to operate the two nuclear units at STP expire in 2027 and 2028. After expiration of the licenses, STP is expected to be decommissioned using the decontamination method. CPL estimates its portion of the costs of decommissioning STP to be $289 million in 1999 nondiscounted dollars. CPL is accruing and recovering these decommissioning costs through rates based on the service life of STP at a rate of $8 million per year.

Decommissioning costs recovered from customers are deposited in external trusts. In 2000 and 1999 I&M deposited in its decommissioning trust an additional $6 million and $4 million, respectively, related to special regulatory commission approved funding for decommissioning of the Cook Plant. Trust fund earnings increase the fund assets and the recorded liability and decrease the amount needed to be recovered from ratepayers. Decommissioning costs including interest, unrealized gains and losses and expenses of the trust funds are recorded in other operation expense for Cook Plant. For STP, nuclear decommissioning costs are recorded in other operation expense, interest income of the trusts are recorded in nonoperating income and interest expense of the trust funds are included in interest charges. During 1999 and 1998 I&M withdrew $8 million and $3 million, respectively, from the trust funds for decommissioning of the original steam generators removed from Cook Plant Unit 2.

On the AEP Consolidated Balance Sheets, nuclear decommissioning trust assets are included in other assets and a corresponding nuclear decommissioning liability is included in other noncurrent liabilities. On CPL's balance sheets, the nuclear decommissioning liability is included in electric utility plant-accumulated depreciation and amortization. At December 31, 2000 and 1999, the decommissioning liability for Cook Plant and STP combined totals $654 million and $587 million, respectively.

*Shareholders' Litigation – Affecting AEP*

On June 23, 2000, a complaint was filed in the U.S. District Court for the Eastern District of New York seeking unspecified compensatory damages against AEP and four former or present officers. The individual plaintiff also seeks certification as the representative of a class consisting of all persons and entities who purchased or otherwise acquired AEP common stock between July 25, 1997, and June 25, 1999. The complaint alleges that the defendants knowingly violated federal securities laws by disseminating materially false and misleading statements concerning, among other things, the undisclosed materially impaired condition of the Cook Plant, AEP's inability to properly monitor, manage, repair, supervise and report on operations at the Cook Plant and the materially adverse conditions these problems were having, and would continue to have, on AEP's deteriorating financial condition, and ultimately on AEP's operations, liquidity and stock price. Four other similar class action complaints have been filed and the court has consolidated the five cases. The plaintiffs filed a consolidated complaint pursuant to this court order. This case has been transferred to the U.S. District Court for the Southern District of Ohio. Although management believes these shareholder actions are without merit and intends to oppose them vigorously, management cannot predict the outcome of this litigation or its impact on results of operations, cash flows or financial condition.

*Municipal Franchise Fee Litigation – Affecting AEP and CPL*

CPL has been involved in litigation regarding municipal franchise fees in Texas as a result of a class action suit filed by the City of San Juan, Texas in 1996. The City of San Juan claims CPL underpaid municipal franchise fees and seeks damage of up to $300 million plus attorney's fees. CPL filed a counterclaim for overpayment of franchise fees.

During 1997, 1998 and 1999 the litigation moved procedurally through the Texas Court System and was sent to mediation without resolution.

In 1999 a class notice was mailed to each of the cities served by CPL. Over 90 of the 128 cities declined to participate in the lawsuit. However, CPL has pledged that if any final, non-appealable court decision in the litigation awards a judgement against CPL for a franchise underpayment, CPL will extend the principles of that decision, with regard to any franchise underpayment, to the cities that declined to participate in the litigation. In December 1999, the court ruled that the class of plaintiffs would consist of approximately 30 cities. A trial date for June 2001 has been set.

Although management believes that it has substantial defenses to the cities' claims and intends to defend itself against the cities' claims and pursue its counterclaims vigorously, management cannot predict the outcome of this litigation or its impact on results of operations, cash flows or financial condition.

*Texas Base Rate Litigation – Affecting AEP and CPL*

In November 1995 CPL filed with the PUCT a request to increase its retail base rates by $71 million. In October 1997 the PUCT issued a final order which lowered CPL's annual retail base rates by $19 million from the rate level which existed prior to May 1996. The PUCT also included a "glide path" rate methodology in the final order pursuant to which annual rates were reduced by $13 million beginning May 1, 1998 with an additional annual reduction of $13 million commencing on May 1, 1999.

CPL appealed the final order to the Travis District Court. The primary issues being appealed include: the classification of $800 million of invested capital in STP as ECOM and assigning it a lower return on equity than other generation property; the use of the "glide path" rate reduction methodology; and an $18 million disallowance of service billings from an affiliate, CSW Services. As part of the appeal, CPL sought a temporary injunction to prohibit the PUCT from implementing the "glide path" rate reduction methodology. The temporary injunction was denied and the "glide path" rate reduction was implemented. In February 1999 the Travis District Court affirmed the PUCT order in regard to the three major items discussed above.

CPL appealed the Travis District Court's findings to the Texas Appeals Court which in July 2000, issued its opinion upholding the Travis District Court except for the disallowance of affiliated service company billings. Under Texas law, specific findings regarding affiliate transactions must be made by PUCT. In regards to the affiliate service billing issue, the findings were not complete in the opinion of the Texas Appeals Court who remanded the issue back to PUCT.

CPL has sought a rehearing of the Texas Appeals Court's opinion. The Texas Appeals Court has requested briefs related to CPL's rehearing request from interested parties. Management is unable to predict the final resolution of its appeal. If the appeal is unsuccessful the PUCT's 1997 order will continue to adversely affect results of operations and cash flows.

As part of the AEP/CSW merger approval process in Texas, a stipulation agreement was approved which resulted in the withdrawal of the appeal related to the "glide path" rate methodology. CPL will continue its appeal of the ECOM classification for STP property and the disallowed affiliated service billings.

*Lignite Mining Agreement Litigation – Affecting AEP and SWEPCo*

SWEPCo and CLECO are each a 50% owner of Dolet Hills Power Station Unit 1 and jointly own lignite reserves in the Dolet Hills area of northwestern Louisiana. In 1982, SWEPCo and CLECO entered into a lignite mining agreement with DHMV, a partnership for the mining and delivery of lignite from a portion of these reserves.

In April 1997, SWEPCo and CLECO sued DHMV and its partners in U.S. District Court for the Western District of Louisiana seeking to enforce various obligations of DHMV under the lignite mining agreement, including provisions relating to the quality of delivered lignite, pricing, and mine reclamation practices. In June 1997, DHMV filed an answer denying the allegations in the suit and filed a counterclaim asserting various contract-related claims against SWEPCo and CLECO. SWEPCo and CLECO have denied the allegations contained in the counterclaims. In January 1999, SWEPCo and CLECO amended the claims against DHMV to include a request that the lignite mining agreement be terminated.

In April 2000, the parties agreed to settle the litigation. As part of the settlement, DHMV's interest in the mining operations and related debt and other obligations will be purchased by SWEPCo and CLECO. The closing date for the settlement has been extended from December 31, 2000 to March 31, 2001. The litigation has been stayed until April 2001 to give the parties time to consummate the settlement agreement.

Management believes that the resolution of this matter will not have a material effect on results of operations, cash flows or financial condition.

*Federal EPA Complaint and Notice of Violation – Affecting AEP, APCo, CSPCo, I&M, and OPCo*

Under the Clean Air Act, if a plant undertakes a major modification that directly results in an emissions increase, permitting requirements might be triggered and the plant may be required to install additional pollution control technology. This requirement does not apply to activities such as routine maintenance, replacement of degraded equipment or failed components, or other repairs needed for the reliable, safe and efficient operation of the plant.

AEP, APCo, CSPCo, I&M, and OPCo have been involved in litigation regarding generating plant emissions under the Clean Air Act. In 1999 Notices of Violation were issued and complaints were filed by Federal EPA in various U.S. District Courts alleging APCo, CSPCo, I&M, OPCo and a number of unaffiliated utilities made modifications to generating units at certain of their coal-fired generating plants over the course of the past 25 years that extended unit operating lives or increased unit generating capacity without a preconstruction permit in violation of the Clean Air Act. The complaint was amended in March 2000 to add allegations for certain generating units previously named in the complaint and to include additional generating units previously named only in the Notices of Violation in the complaint.

A number of northeastern and eastern states were granted leave to intervene in the Federal EPA's action against the AEP System under the Clean Air Act. A lawsuit against power plants owned by certain AEP System operating companies alleging similar violations to those in the Federal EPA complaint and Notices of Violation was filed by a number of special interest groups and has been consolidated with the Federal EPA action.

The Clean Air Act authorizes civil penalties of up to $27,500 per day per violation at each generating unit ($25,000 per day prior to January 30, 1997). Civil penalties, if ultimately imposed by the court, and the cost of any required new pollution control equipment, if the court accepts Federal EPA's contentions, could be substantial.

On May 10, 2000, the AEP System companies filed motions to dismiss all or portions of the complaints. Briefing on these motions was completed on August 2, 2000. On February 23, 2001, the government filed a motion for partial summary judgement seeking a determination that four projects undertaken on units at Sporn, Cardinal and Clinch River plants do not constitute "routine maintenance, repair and replacement" as used in the Clean Air Act. Management believes its maintenance, repair and replacement activities were in conformity with the Clean Air Act and intends to vigorously pursue its defense.

In the event the AEP System companies do not prevail, any capital and operating costs of additional pollution control equipment that may be required as well as any penalties imposed would adversely affect future results of operations, cash flows and possibly financial condition unless such costs can be recovered through regulated rates, and where states are deregulating generation, unbundled transition period generation rates, stranded cost wires charges and future market prices for electricity.

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

*NOx Reductions – Affecting AEP, AEGCo, APCo, CPL, CSPCo, I&M, KPCo, OPCo and SWEPCo*

Federal EPA issued a NOx rule that required substantial reductions in NOx emissions in a number of eastern states, including certain states in which the AEP System's generating plants are located. A number of utilities, including several AEP System companies, filed petitions seeking a review of the final rule in the D.C. Circuit Court. In March 2000, the D.C. Circuit Court issued a decision generally upholding the NOx rule. The D.C. Circuit Court issued an order in August 2000 which extends the final compliance date to May 31, 2004. In September 2000 following denial by the D.C. Circuit Court of a request for rehearing, the industry petitioners, including the AEP System companies, petitioned the U.S. Supreme Court for review, which was denied.

In December 2000 Federal EPA ruled that eleven states, including states in which AEGCo's, APCo's, CSPCo's, I&M's, KPCo's and OPCo's generating units are located, failed to submit plans to comply with the mandates of the NOx rule. This determination means that those states could face stringent sanctions within the next 24 months including limits on construction of new sources of air emissions, loss of federal highway funding and possible Federal EPA takeover of state air quality management programs.

In January 2000 Federal EPA adopted a revised rule granting petitions filed by certain northeastern states under Section 126 of the Clean Air Act seeking significant reductions in nitrogen oxide emissions from utility and industrial sources. The rule imposes emissions reduction requirements comparable to the NOx rule beginning May 1, 2003, for most of AEP's coal-fired generating units. Certain AEP operating companies and other utilities filed petitions for review in the D.C. Circuit Court. Briefing has been completed and oral argument was held in December 2000.

In a related matter, on April 19, 2000, the Texas Natural Resource Conservation Commission adopted rules requiring significant reductions in NOx emissions from utility sources, including CPL and SWEPCo. The rule's compliance date is May 2003 for CPL and May 2005 for SWEPCo.

In June 2000 OPCo announced that it was beginning a $175 million installation of selective catalytic reduction technology (expected to be operational in 2001) to reduce NOx emissions on its two-unit 2,600 MW Gavin Plant. Construction of selective catalytic reduction technology on Amos Plant Unit 3, which is jointly owned by OPCo and APCo, and APCo's Mountaineer Plant is scheduled to begin in 2001. The Amos and Mountaineer projects (expected to be completed in 2002) are estimated to cost a total of $230 million ($145 million for APCo and $85 million for OPCo).

Preliminary estimates indicate that compliance with the NOx rule upheld by the D.C. Circuit Court as well as compliance with the Texas Natural Resource Conservation Commission rule and the Section 126 petitions could result in required capital expenditures of approximately $1.6 billion, including the amounts discussed in the previous paragraph, for AEP Consolidated. Estimated compliance costs by registrant subsidiaries are as follows:

| | (in millions) |
|---|---|
| AEGCo | $125 |
| APCo | 365 |
| CPL | 57 |
| CSPCo | 106 |
| I&M | 202 |
| KPCo | 140 |
| OPCo | 606 |
| SWEPCo | 28 |

Since compliance costs cannot be estimated with certainty, the actual cost to comply could be significantly different than the preliminary estimates depending upon the compliance alternatives selected to achieve reductions in NOx emissions. Unless any capital and operating costs of additional pollution control equipment are recovered from customers through regulated rates and/or future market prices for electricity where generation is deregulated, they will have an adverse effect on future results of operations, cash flows and possibly financial condition.

*COLI Litigation – Affecting AEP, APCo, CSPCo, I&M, KPCo and OPCo*

On February 20, 2001, the U.S. District Court for the Southern District of Ohio ruled against the AEP System companies in their suit against the United States over deductibility of interest claimed in their consolidated federal income tax return related to a COLI program. The suit was filed to resolve the IRS' assertion that interest deductions for the COLI program should not be allowed. In 1998 and 1999 APCo, CSPCo, I&M, KPCo and OPCo paid the disputed taxes and interest attributable to COLI interest deductions for taxable years 1991-98 for APCo, CSPCo, I&M and OPCo and 1992-98 for KPCo to avoid the potential assessment by the IRS of additional interest on the contested tax. The payments were included in other assets on AEP's Consolidated Balance Sheet and in Other Property and Investment on the subsidiaries' balance sheets pending the resolution of this matter. As a result of the U.S. District Court's decision to deny the COLI interest deductions, net income was reduced for AEP Consolidated by $319 million in 2000. The appeal of this decision is planned. The earnings reductions for affected registrant subsidiaries are as follows:

| | (in millions) |
|---|---|
| APCo | $ 82 |
| CSPCo | 41 |
| I&M | 66 |
| KPCo | 8 |
| OPCo | 118 |

*Other* – AEP and its registrant subsidiaries are involved in a number of other legal proceedings and claims. While management is unable to predict the ultimate outcome of these matters, it is not expected that their resolution will have a material adverse effect on results of operations, cash flows or financial condition.

**9. Acquisitions:**

AEP completed two energy related acquisitions in 1998 through a subsidiary, AEPR. Both acquisitions have been accounted for using the purchase method. On December 31, 1998 CitiPower, an Australian distribution utility, that serves approximately 250,000 customers in Melbourne with 3,100 miles of distribution lines in a service area of approximately 100 square miles was acquired. All of the stock of CitiPower was acquired for approximately $1.1 billion. The acquisition of CitiPower had no effect on the results of operations for 1998 and a full year of CitiPower's results of operations are included in the consolidated statements of income for 1999 and 2000. Assets acquired and liabilities assumed have been recorded at their fair values. Based on an independent appraisal, $616 million of the purchase price was allocated to retail and wholesale distribution licenses which are being amortized on a straight-line basis over 20 years and 40 years, respectively. The excess of cost over fair value of the net assets acquired was approximately $34 million and is recorded as goodwill and is being amortized on a straight-line basis over 40 years.

On December 1, 1998 AEPR acquired Louisiana Intrastate Gas (LIG) with midstream gas operations that include a fully integrated natural gas gathering, processing, storage and transportation operation in Louisiana and a gas trading and marketing operation. LIG was acquired for approximately $340 million, including working capital funds with one month of earnings reflected in AEP's consolidated results of operations for the year ended December 31, 1998. A full year of LIG's results of operations is included in AEP's consolidated statements of income for 1999 and 2000. Assets acquired and liabilities assumed have been recorded at their fair values. The excess of cost over fair value of the net assets acquired was approximately $158 million for the midstream gas storage operations and $17 million for the gas trading and marketing operation. The goodwill is being amortized on a straight-line basis over 40 years and 10 years, respectively.

**10. International Investments:**

CSW International owns a 44% equity interest in Vale, a Brazilian electric operating company which it had purchased for a total of $149 million. The investment is covered by a put option, which, if exercised, requires CSW International's partners in Vale to purchase CSW International's Vale shares at a minimum price equal to the U.S. dollar equivalent of CSW International's purchase price. As a result, management has concluded that CSW International's investment carrying amount will not be reduced below the put option value unless it is deemed to be a permanent impairment and CSW International's partners in Vale are deemed unable to fulfill their responsibilities under the put option. Vale has experienced losses from operations and CSW International's investment has been affected by the devaluation of the Brazilian Real. CSW International's cumulative equity share of these operating and foreign currency translation losses through December 31, 2000 is approximately $33 million, net of tax, and $49 million, net of tax, respectively. Pursuant to the put option arrangement, these losses have not been applied to reduce the carrying value of the Vale investment. As a result, CSW International will not recognize any future earnings from Vale until the operating losses are recovered.

In December 2000, CSW International sold its investment in a Chilean electric company for $67 million. A net loss on the sale of $13 million ($9 million after tax) is included in worldwide electric and gas expenses and includes $26 million ($17 million net of tax) of losses from foreign exchange rate changes that were previously reflected in other comprehensive income. In the second quarter of 2000 management determined that the then existing decline in market value of the shares was other than temporary. As a result the investment was written down by $33 million ($21 million after tax) in June 2000. The total loss from both the write down of the Chilean investment to market in the second quarter and from the sale in the fourth quarter was $46 million ($30 million net of tax).

In December 2000 AEPR entered into negotiations to sell its 50% investment in Yorkshire, a U.K. electricity supply and distribution company. On February 26, 2001 an agreement to sell AEPR's 50% interest in Yorkshire was signed. As a result a $43 million impairment writedown ($30 million after tax) was recorded in the fourth quarter of 2000 to reflect the net loss from the expected sale in the first quarter of 2001. The impairment writedown is included in other income (net) on AEP's Consolidated Statements of Income.

**11. Staff Reductions:**

During 1998 an internal evaluation of the power generation organization was conducted with a goal of developing an optimum organizational structure for a competitive generation market. The study was completed in October 1998 and called for the elimination of approximately 450 positions across the AEP System. In addition, a review of energy delivery staffing levels in 1998 identified 65 AEP System positions for elimination.

A provision for severance costs totaling $26 million was recorded in December 1998 for reductions in power generation and energy delivery staffs and was charged to maintenance and other operation expense. The power generation and energy delivery staff reductions were made in the first quarter of 1999. The amount of severance benefits paid was not significantly different from the amount accrued.

The following table shows the staff reductions information for the applicable registrant companies:

| Company | Total Number of Employees | Severance Accrual Amount |
|---|---|---|
| | | (in millions) |
| APCo | 180 | $7.6 |
| CSPCo | 70 | 3.4 |
| I&M | 80 | 3.7 |
| KPCo | 35 | 1.9 |
| OPCo | 150 | 8.6 |

**12. Benefit Plans:**

In the U.S. the AEP System sponsors two qualified pension plans and two nonqualified pension plans. All employees in the U.S., except participants in the UMWA pension plans are covered by one or both of the pension plans. OPEB plans are sponsored by the AEP System to provide medical and death benefits for retired employees in the U.S.

The foreign pension plans are for employees of SEEBOARD in the U.K. and CitiPower in Australia. The majority of SEEBOARD's employees joined a pension plan that is administered for the U.K.'s electricity industry. The assets of this plan are actuarially valued every three years. SEEBOARD and its participating employees both contribute to the plan. Subsequent to July 1, 1995, new employees were no longer able to participate in that plan and two new pension plans were made available to new employees of SEEBOARD. CitiPower sponsors a defined benefit pension plan that covers all employees.

The following tables provide a reconciliation of the changes in the plans' benefit obligations and fair value of assets over the two-year period ending December 31, 2000, and a statement of the funded status as of December 31 for both years:

| | U.S. Pension Plans | | Foreign Pension Plans | | U.S. OPEB Plans | |
|---|---|---|---|---|---|---|
| | 2000 | 1999 | 2000 | 1999 | 2000 | 1999 |
| | | | (in millions) | | | |
| Reconciliation of benefit obligation: | | | | | | |
| Obligation at January 1 | $2,934 | $3,117 | $1,176 | $1,147 | $1,365 | $1,297 |
| Service Cost | 60 | 71 | 13 | 15 | 29 | 33 |
| Interest Cost | 227 | 211 | 64 | 59 | 106 | 90 |
| Participant Contributions | - | - | 5 | 4 | 7 | 9 |
| Plan Amendments | (71)(a) | 7 (b) | - | 7 (c) | (67) (d) | - |
| Foreign Currency Translation Adjustment | - | - | (95) | (26) | - | - |
| Actuarial (Gain) Loss | 218 | (300) | 80 | 37 | 262 | - |
| Benefit Payments | (207) | (172) | (64) | (67) | (85) | (74) |
| Curtailments | - | - | - | - | 51 (e) | 10 (e) |
| Obligation at December 31 | $3,161 | $2,934 | $1,179 | $1,176 | $1,668 | $1,365 |
| Reconciliation of fair value of plan assets: | | | | | | |
| Fair value of plan assets at January 1 | $3,866 | $3,665 | $1,405 | $1,338 | $668 | $560 |
| Actual Return on Plan Assets | 250 | 370 | 55 | 156 | 2 | 71 |
| Company Contributions | 2 | 2 | - | 7 | 112 | 103 |
| Participant Contributions | - | - | 5 | 4 | 7 | 9 |
| Foreign Currency Translation Adjustment | - | - | (111) | (33) | - | - |
| Benefit Payments | (207) | (172) | (64) | (67) | (85) | (74) |
| Fair value of plan assets at December 31 | $3,911 | $3,865 | $1,290 | $1,405 | $704 | $669 |
| Funded status: | | | | | | |
| Funded status at December 31 | $ 750 | $ 931 | $111 | $ 229 | $(964) | $(696) |
| Unrecognized Net Transition (Asset) Obligation | (23) | (31) | - | - | 298 | 434 |
| Unrecognized Prior-Service Cost | (12) | 71 | 10 | 11 | - | - |
| Unrecognized Actuarial (Gain) Loss | (628) | (954) | (67) | (177) | 448 | 135 |
| Prepaid Benefit (Accrued Liability) | $ 87 | $ 17 | $ 54 | $ 63 | $(218) | $(127) |

(a) One of the qualified pension plans converted to the cash balance pension formula from a final average pay formula.
(b) Early retirement factors for one of the pension plans was changed to provide more generous benefits to participants retiring between ages 55 and 60.
(c) SEEBOARD made a one-time payment to all retired participants.
(d) Change to a service-related formula for retirement health care costs and a 50% of pay life insurance benefit for retiree life insurance.
(e) Related to the shutdown of OPCo's affiliated coal mine operations.

The following table provides the amounts recognized in AEP's consolidated balance sheets as of December 31 of both years:

| | U.S. Pension Plan | | Foreign Pension Plans | | U.S. OPEB Plans | |
|---|---|---|---|---|---|---|
| | 2000 | 1999 | 2000 | 1999 | 2000 | 1999 |
| | | | (in millions) | | | |
| Prepaid Benefit Costs | $ 159 | $ 145 | $54 | $63 | $ - | $ - |
| Accrued Benefit Liability | (72) | (128) | - | - | (218) | (127) |
| Additional Minimum Liability | (24) | (14) | - | - | N/A | N/A |
| Intangible Asset | 14 | 8 | - | - | N/A | N/A |
| Accumulated Other Comprehensive Income | 10 | 6 | - | - | N/A | N/A |
| Net Amount Recognized | $ 87 | $ 17 | $54 | $63 | $(218) | $(127) |
| Other Comprehensive (Income) Expense Attributable to Change in Additional Pension Liability Recognition | $4 | $(2) | - | - | N/A | N/A |

N/A = Not Applicable

The AEP System's nonqualified pension plans had accumulated benefit obligations in excess of plan assets of $41 million and $26 million at December 31, 2000 and $29 million and $23 million at December 31, 1999. There are no plan assets in the nonqualified plans.

The AEP System's OPEB plans had accumulated benefit obligations in excess of plan assets of $964 million and $696 million at December 31, 2000 and 1999, respectively.

The following table provides the components of AEP's net periodic benefit cost for the plans for fiscal years 2000, 1999 and 1998:

| | U.S. Pension Plans | | | Foreign Pension Plans | | | U.S. OPEB Plans | | |
|---|---|---|---|---|---|---|---|---|---|
| | 2000 | 1999 | 1998 | 2000 | 1999 | 1998 | 2000 | 1999 | 1998 |
| | | | | (in millions) | | | | | |
| Service cost | $ 60 | $ 71 | $ 67 | $ 13 | $ 15 | $ 14 | $ 29 | $ 33 | $ 26 |
| Interest cost | 227 | 211 | 202 | 64 | 59 | 68 | 106 | 90 | 76 |
| Expected return on plan assets | (321) | (299) | (269) | (75) | (71) | (77) | (57) | (49) | (40) |
| Amortization of transition (asset) obligation | (8) | (8) | (8) | - | - | - | 41 | 43 | 41 |
| Amortization of prior-service cost | 13 | 12 | 9 | 1 | - | - | - | - | - |
| Amortization of net actuarial (gain) loss | (39) | (15) | (3) | - | - | - | 4 | 5 | (2) |
| Net periodic benefit cost | (68) | (28) | (2) | 3 | 3 | 5 | 123 | 122 | 101 |
| Curtailment loss(a) | - | - | - | - | - | - | 79 | 18 | 24 |
| Net periodic benefit cost after curtailments | $(68) | $ (28) | $ (2) | $ 3 | $ 3 | $ 5 | $202 | $140 | $125 |

(a) Curtailment charges were recognized during 2000, 1999 and 1998 for the shutdown of affiliated coal mine operations.

The following table provides the net periodic benefit cost (credit) for the plans by the following AEP registrant subsidiaries for fiscal years 2000, 1999 and 1998:

| | U.S. Pension Plans | | | U.S OPEB Plans | | |
|---|---|---|---|---|---|---|
| | 2000 | 1999 | 1998 | 2000 | 1999 | 1998 |
| | | | (in thousands) | | | |
| APCo | $(14,047) | $(3,925) | $ 778 | $ 22,139 | $19,431 | $16,569 |
| CPL | (2,986) | (4,270) | (2,850) | 6,656 | 7,595 | 6,599 |
| CSPCo | (10,905) | (4,893) | (1,410) | 9,643 | 8,623 | 7,467 |
| I&M | (8,565) | (1,259) | 2,104 | 14,155 | 13,664 | 11,994 |
| KPCo | (2,075) | (393) | 322 | 2,364 | 2,652 | 2,113 |
| OPCo | (15,041) | (4,979) | 26 | 116,205 | 52,518 | 54,578 |
| PSO | (2,196) | (3,129) | (2,190) | 4,277 | 5,516 | 4,369 |
| SWEPCo | (2,606) | (3,734) | (2,581) | 4,152 | 4,913 | 3,673 |
| WTU | (1,585) | (2,221) | (1,478) | 2,929 | 3,377 | 3,002 |

The assumptions used in the measurement of the AEP System's benefit obligations are shown in the following tables:

| | U.S. Pension Plans | | | Foreign Pension Plans | | | U.S. OPEB Plans | | |
|---|---|---|---|---|---|---|---|---|---|
| | 2000 % | 1999 % | 1998 % | 2000 % | 1999 % | 1998 % | 2000 % | 1999 % | 1998 % |
| Weighted-average assumptions as of December 31: | | | | | | | | | |
| Discount rate | 7.50 | 8.00 | 6.75 | 5-5.5 | 5.5-6 | 5-5.5 | 7.50 | 8.00 | 6.75 |
| Expected return on plan assets | 9.00 | 9.00 | 9.00 | 6-7.5 | 6.5-7.5 | 6.25-7 | 8.75 | 8.75 | 8.75 |
| Rate of compensation increase | 3.2 | 3.8 | 3.8 | 3.5-4.0 | 4-4.5 | 3.5-4 | N/A | N/A | N/A |

For measurement purposes, a 6.0% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2001. The rate was assumed to decrease gradually each year to a rate of 5.1% through 2005 and remain at that level thereafter.

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 | $ 15 | $ (13) |
| Effect on the health care component of the accumulated postretirement benefit obligation | 197 | (162) |

*AEP System Savings Plans* - The AEP System Savings Plans are defined contribution plans offered to non-UMWA U.S. employees. The cost for contributions to these plans totaled $37 million in 2000, $36 million in 1999 and $35 million in 1998. Beginning in 2001 AEP's contributions to the plans will increase to 4.5% of the initial 6% of employee pay contributed from the current 3% of the initial 6% of employee base pay contributed.

The following table provides the cost for contributions to the savings plans by the following AEP registrant subsidiaries for fiscal years 2000, 1999 and 1998:

| | 2000 | 1999 | 1998 |
|---|---|---|---|
| | (in thousands) | | |
| APCo | $3,988 | $4,091 | $4,276 |
| CPL | 3,161 | 3,284 | 3,078 |
| CSPCo | 1,638 | 1,679 | 1,830 |
| I&M | 4,231 | 3,996 | 4,017 |
| KPCo | 544 | 561 | 714 |
| OPCo | 3,713 | 3,744 | 3,978 |
| PSO | 2,306 | 2,435 | 2,230 |
| SWEPCo | 2,880 | 2,961 | 2,728 |
| WTU | 1,708 | 1,766 | 1,594 |

Other UMWA Benefits – AEP and OPCo provide UMWA pension, health and welfare benefits for certain unionized mining employees, retirees, and their survivors who meet eligibility requirements. The benefits are administered by UMWA trustees and contributions are made to their trust funds. Contributions are based on hours worked and are expensed as paid as part of the cost of active mining operations and were not material in 2000, 1999 and 1998.

**13. Stock-Based Compensation:**

In 2000, AEP adopted a Long-term Incentive Plan under which a maximum of 15,700,000 shares of common stock can be issued to key employees. Under the plan, the exercise price of each option granted equals the market price of AEP's common stock on the date of grant. These options will vest in equal increments, annually, over a three-year period beginning on January 1, 2002 with a maximum exercise term of ten years.

CSW maintained a stock option plan prior to the merger with AEP. Effective with the merger, all CSW stock options outstanding were converted into AEP stock options at an exchange ratio of one CSW stock option for 0.6 of an AEP stock option. The exercise price for each CSW stock option was adjusted for the exchange ratio. The provisions of the CSW stock option plan will continue in effect until all options expire or there are no longer options outstanding. Under the CSW stock option plan, the option exercise price was equal to the stock's market price on the date of grant. The grant vested over three years, one-third on each of the first three anniversary dates of the grant, and expires 10 years after the original grant date. All CSW stock options were fully vested at December 31, 2000.

The following table summarizes share activity in the above plans, and the weighted-average exercise price:

| | 2000 | | 1999 | | 1998 | |
|---|---|---|---|---|---|---|
| | Options (in thousands) | Weighted Average Exercise Price | Options (in thousands) | Weighted Average Exercise Price | Options (in thousands) | Weighted Average Exercise Price |
| Outstanding at beginning of year | 825 | $40 | 866 | $40 | 1,141 | $40 |
| Granted | 6,046 | $36 | - | $ - | - | $ - |
| Exercised | (26) | $36 | (22) | $38 | (202) | $40 |
| Forfeited | (235) | $39 | (19) | $43 | (73) | $40 |
| Outstanding at end of year | 6,610 | $36 | 825 | $40 | 866 | $40 |
| Options Exercisable at end of year | 588 | $41 | 707 | $42 | 606 | $43 |

The weighted-average fair value of options granted in 2000 is $36 per share. No options were granted in 1999 or 1998. Shares outstanding under the stock option plan have exercise prices ranging from $35 to $49 and a weighted-average remaining contractual life of 9.2 years.

If compensation expense for stock options had been determined based on the fair value at the grant date, net income and earnings per share would have been the pro forma amounts shown below:

| | 2000 | 1999 | 1998 |
|---|---|---|---|
| Pro forma net income (in millions) | $264 | $972 | $975 |
| Pro forma earnings per share (basic and diluted) | $0.82 | $3.03 | $3.06 |

The pro forma amounts are not representative of the effects on reported net income for future years.

The fair value of each option award is estimated on the date of grant using the Black-Scholes option-pricing model with the following assumptions used to estimate the fair value of options granted in 2000: dividend yield of 6.02%; expected stock price volatility of 24.75%; risk-free interest rate of 5.02% and expected life of option of 7 years.

## 14. Business Segments:

AEP's principal business segment is its cost-based rate regulated Domestic Electric Utility business consisting of eleven regulated utility operating companies providing generation, distribution and transmission electric services in eleven states. Also included in this segment are AEP's electric power wholesale marketing and trading activities conducted within two transmission systems of the AEP System.

The AEP consolidated income statement caption "Revenues-Domestic Electric Utility Operations" includes both the retail and wholesale domestic electricity supply businesses which are cost-based rate regulated on a bundled basis with transmission and distribution services in Kentucky, Indiana, Michigan, Louisiana, Oklahoma and Tennessee and are in the process of transitioning to customer choice market based pricing in Arkansas, Ohio, Texas, WV and Virginia. Since the domestic electric utility companies have not yet functionally or structurally separated their retail and wholesale electricity supply business from their regulated transmission and distribution service business, separate financial data is not available and the Domestic Electric Utilities business will continue to be reported as one business segment which is the only reportable segment for the domestic electric operating subsidiaries. Therefore all registrant subsidiaries have one reportable segment, a regulated vertically integrated electricity generation and energy delivery business. All other activities for these registrant subsidiaries are insignificant. In 2000, 1999 and 1998 all the registrant subsidiaries revenues are derived from the generation, sale and delivery of electricity in the U.S.

The AEP consolidated income statement caption "Revenues-Worldwide Electric and Gas Operations" includes three segments: Foreign Energy Delivery, Worldwide Energy Investments and other. The Foreign Energy Delivery segment includes investments in overseas electric distribution and supply companies (SEEBOARD and Yorkshire in the U.K. and CitiPower in Australia).

The Worldwide Energy Investments segment represents domestic and international investments in energy-related gas and electric projects including the development and management of those projects. Such investment activities include electric generation in Florida, Texas, Colorado, Brazil and Mexico, and natural gas pipeline, storage and other natural gas services in the U.S.

The other segment which is included in the AEP consolidated income statement as part of Worldwide Electric and Gas Operations includes non-regulated electric marketing and trading activities outside of AEP's marketing area (beyond two transmission systems from the AEP System) gas marketing and trading activities, telecommunication services, and the marketing of various energy related products and services.

In the fourth quarter of 2000, management announced its intent to functionally and structurally separate its operations into two main business segments, a non-regulated business and a regulated business. Separation of AEP's regulated bundled generation, distribution and transmission businesses into an unbundled non-regulated generation business and regulated unbundled distribution and transmission business will not be completed until the required regulatory approvals are obtained and the electric operating subsidiaries operating in states that are deregulating the generation business are structurally separated and the remaining subsidiaries functionally separated and the necessary changes are made to their accounting software, books, and records. Management expects to begin reporting certain segmented information by the new business segments in the near future.

| Year | Domestic* Electric Utilities | Foreign Energy Delivery | Worldwide Energy Investments | Other | Reconciling Adjustments | AEP Consolidated |
|---|---|---|---|---|---|---|
| | | | (in millions) | | | |
| 2000 | | | | | | |
| Revenues from: | | | | | | |
| External unaffiliated customers | $10,827 | $1,934 | $ 836 | $ 97 | - | $13,694 |
| Transactions with other operating segments | - | - | 147 | 391 | $(538) | - |
| Interest expense | 734 | 163 | 129 | 91 | (60) | 1,057 |
| Depreciation, depletion and amortization expense | 1,062 | 149 | 25 | 13 | (187) | 1,062 |
| Income tax expense (benefit) | 641 | (16) | (19) | (9) | - | 597 |
| Segment net income (loss) | 211 | 125 | (56) | (13) | - | 267 |
| Total assets | 35,741 | 4,446 | 2,089 | 12,272 | - | 54,548 |
| Investments in equity method subsidiaries | - | 427 | 360 | 77 | - | 864 |
| Gross property additions | 1,386 | 177 | 149 | 61 | - | 1,773 |
| 1999 | | | | | | |
| Revenues from: | | | | | | |
| External unaffiliated customers | $ 9,838 | $2,023 | $ 583 | $ (37) | - | $12,407 |
| Transactions with other operating segments | - | - | 70 | 246 | $(316) | - |
| Interest expense | 688 | 172 | 109 | 55 | (47) | 977 |
| Depreciation, depletion and amortization expense | 1,011 | 166 | 26 | 9 | (201) | 1,011 |
| Income tax expense (benefit) | 490 | 18 | (10) | (16) | - | 482 |
| Segment net income (loss) | 794 | 170 | 34 | (26) | - | 972 |
| Total assets | 27,288 | 4,739 | 1,669 | 2,023 | - | 35,719 |
| Investments in equity method subsidiaries | - | 412 | 420 | 57 | - | 889 |
| Gross property additions | 1,215 | 206 | 205 | 54 | - | 1,680 |
| 1998 | | | | | | |
| Revenues from: | | | | | | |
| External unaffiliated customers | $ 9,834 | $1,769 | $ 183 | $ 54 | - | $11,840 |
| Transactions with other operating segments | - | - | - | 49 | $ (49) | - |
| Interest expense | 682 | 116 | 68 | 51 | (38) | 879 |
| Depreciation, depletion and amortization expense | 989 | 95 | 13 | 7 | (115) | 989 |
| Income tax expense (benefit) | 532 | 4 | (14) | (20) | - | 502 |
| Segment net income (loss) | 884 | 155 | (26) | (38) | - | 975 |
| Total assets | 25,546 | 4,504 | 1,672 | 1,543 | - | 33,265 |
| Investments in equity method subsidiaries | - | 352 | 287 | 59 | - | 698 |
| Gross property additions | 729 | 1,259 | 712 | 90 | - | 2,790 |

*Includes the domestic generation retail and wholesale supply businesses a significant portion of which is undergoing a transition from regulated cost based bundled rates to open access market pricing but which have not yet been unbundled i.e., structurally separated from the distribution and transmission portions of the vertically integrated electric utility business.

Geographic Areas

| | Revenues | | | |
|---|---|---|---|---|
| | United States | United Kingdom | Other Foreign | AEP Consolidated |
| | | (in millions) | | |
| 2000 | $11,663 | $1,632 | $399 | $13,694 |
| 1999 | 10,353 | 1,705 | 349 | 12,407 |
| 1998 | 10,063 | 1,769 | 8 | 11,840 |

| | Long-Lived Assets | | | |
|---|---|---|---|---|
| | United States | United Kingdom | Other Foreign | AEP Consolidated |
| | | (in millions) | | |
| 2000 | $20,463 | $1,220 | $710 | $22,393 |
| 1999 | 19,958 | 1,124 | 783 | 21,865 |
| 1998 | 19,752 | 1,102 | 665 | 21,519 |

## 15. Financial Instruments, Credit and Risk Management:

AEP and its subsidiaries are subject to market risk as a result of changes in commodity prices, foreign currency exchange rates, and interest rates. AEP has wholesale electricity and gas trading and marketing operations that manage the exposure to commodity price movements using physical forward purchase and sale contracts at fixed and variable prices, and financial derivative instruments including exchange traded futures and options, over-the-counter options, swaps and other financial derivative contracts at both fixed and variable prices.

In the first quarter of 1999 AEP adopted the Financial Accounting Standards Board's EITF 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities". The EITF requires that all open energy trading contracts be marked-to-market. The effect on the Consolidated Statements of Income of marking open trading contracts to market in the AEP System's regulated jurisdictions are deferred as regulatory assets or liabilities in accordance with SFAS 71 for the portion of those open electricity trading transactions within AEP's marketing area that are included in cost of service on a settlement basis for ratemaking purposes. Open electricity trading transactions within AEP's marketing area allocated to non-regulated jurisdictions are marked-to-market and included in revenues from domestic electric utility operations. Open electricity trading contracts outside AEP's marketing area are accounted for on a mark-to-market basis and included in revenues from worldwide electric and gas operations. Open gas trading contracts are accounted for on a mark-to-market basis and included in revenues from worldwide electric and gas operations. Unrealized mark-to-market gains and losses from trading of financial instruments are reported as assets and liabilities, respectively.

The amounts of net revenues recorded in 2000 and 1999 for electric and gas trading activities were:

| Revenues - Net Gain (Loss) | 2000 | 1999 |
|---|---|---|
| | (in millions) | |
| Domestic Electric Utility Operations | $ 43 | $27 |
| Worldwide Electric and Gas Operations | 213 | 14 |

The amounts of net revenues recorded in 2000 and 1999 for the registrant subsidiaries were:

| | 2000 | 1999 |
|---|---|---|
| | (in thousands) | |
| APCo | $23,712 | $14,640 |
| CPL | (3,809) | - |
| CSPCo | 22,032 | 5,819 |
| I&M | 29,344 | 6,384 |
| KPCo | 11,792 | 2,182 |
| OPCo | 34,582 | 10,921 |
| PSO | 3,553 | - |
| SWEPCo | (441) | - |
| WTU | (453) | - |

Investment in foreign energy companies and projects exposes AEP to risk of foreign currency fluctuations. AEP is also exposed to changes in interest rates primarily due to short- and long-term borrowings used to fund its business operations. AEP does not presently utilize derivatives to manage its exposures to foreign currency exchange rate movements.

*Market Valuation* - 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 approximates AEP and I&M's best estimate of its fair value.

The book values and fair values of AEP's and the registrant subsidiaries' significant financial instruments at December 31, 2000 and 1999 are summarized in the following table. The fair values of long-term debt and preferred stock subject to mandatory redemption are based on quoted market prices for the same or similar issues and the current dividend or interest rates offered for instruments of the same remaining maturities. The fair value of those financial instruments that are marked-to-market are based on management's best estimates using over-the-counter quotations, exchange prices, volatility factors and a valuation methodology. The estimates presented herein are not necessarily indicative of the amounts that AEP and the registrant subsidiaries could realize in a current market exchange.

| | 2000 | | 1999 | |
|---|---|---|---|---|
| | Book Value | Fair Value | Book Value | Fair Value |
| | (in thousands) | | (in thousands) | |
| **Non-Derivatives** | | | | |
| **AEP Consolidated** | | | | |
| Long-term Debt | $10,754,000 | $10,812,000 | $11,524,000 | $11,037,000 |
| Preferred Stock | 100,000 | 98,000 | 119,000 | 117,000 |
| Trust Preferred Securities | 334,000 | 326,000 | 335,000 | 290,000 |
| **AEGCo** | | | | |
| Long-term Debt | $45 | $45 | $45 | $45 |
| **APCo** | | | | |
| Long-term Debt | $1,605,818 | $1,601,313 | $1,665,307 | $1,580,600 |
| Preferred Stock | 10,860 | 10,725 | 20,310 | 19,700 |
| **CPL** | | | | |
| Long-term Debt | $1,454,559 | $1,463,690 | $1,454,541 | $1,435,083 |
| Trust Preferred Securities | 148,500 | 147,431 | 150,000 | 129,360 |
| **CSPCo** | | | | |
| Long-term Debt | $899,615 | $908,620 | $925,000 | $889,000 |
| Preferred Stock | 15,000 | 14,892 | 25,000 | 25,438 |
| **I&M** | | | | |
| Long-term Debt | $1,388,939 | $1,377,230 | $1,324,326 | $1,283,300 |
| Preferred Stock | 64,945 | 63,941 | 64,945 | 63,500 |
| **KPCo** | | | | |
| Long-term Debt | $330,880 | $335,408 | $365,782 | $359,100 |
| **OPCo** | | | | |
| Long-term Debt | $1,195,493 | $1,176,367 | $1,151,511 | $1,027,000 |
| Preferred Stock | 8,850 | 8,780 | 8,850 | 8,500 |
| **PSO** | | | | |
| Long-term Debt | $470,822 | $476,964 | $384,516 | $378,437 |
| Trust Preferred Securities | 75,000 | 72,180 | 75,000 | 63,390 |
| **SWEPCo** | | | | |
| Long-term Debt | $645,963 | $651,586 | $541,568 | $537,354 |
| Trust Preferred Securities | 110,000 | 106,700 | 110,000 | 97,372 |
| **WTU** | | | | |
| Long-term Debt | $255,843 | $261,315 | $303,686 | $298,220 |

Derivatives

| | 2000 Notional Amount | 2000 Fair Value | 2000 Average Fair Value | 1999 Notional Amount | 1999 Fair Value | 1999 Average Fair Value |
|---|---|---|---|---|---|---|
| | GWH | (in millions) | | GWH | (in millions) | |
| **AEP Consolidated Trading Assets** | | | | | | |
| Electric | | | | | | |
| Futures and Options-NYMEX (net) | - | $ - | $ - | 224 | $ 2 | $ 1 |
| Physicals | 247,330 | 8,845 | 2,758 | 69,509 | 577 | 517 |
| Options - OTC | 8,981 | 215 | 99 | 6,203 | 39 | 62 |
| Swaps | 11,575 | 164 | 60 | 177 | 1 | 1 |
| | MMMBTU | | | MMMBTU | | |
| Gas | | | | | | |
| Futures and Options-NYMEX (net) | - | $ - | $ - | - | $ - | $ - |
| Physicals | 597,251 | 455 | 97 | 345,830 | 37 | 39 |
| Options - OTC | 698,392 | 1,266 | 355 | 192,593 | 54 | 40 |
| Swaps | 4,677,142 | 7,328 | 1,730 | 2,682,033 | 410 | 312 |
| **Trading Liabilities** | | | | | | |
| | GWH | (in millions) | | GWH | (in millions) | |
| Electric | | | | | | |
| Futures and Options-NYMEX (net) | - | $ - | $ - | - | $ - | $ - |
| Physicals | 246,729 | (8,906) | (2,712) | 74,764 | (536) | (498) |
| Options - OTC | 10,368 | (133) | (69) | 8,907 | (43) | (56) |
| Swaps | 11,289 | (144) | (47) | 180 | (2) | (2) |
| | MMMBTU | | | MMMBTU | | |
| Gas | | | | | | |
| Futures and Options-NYMEX (net) | 23,110 | $ (81) | $ (11) | 69,840 | $ (8) | $ (5) |
| Physicals | 442,309 | (420) | (91) | 301,271 | (32) | (26) |
| Options - OTC | 666,304 | (934) | (306) | 227,225 | (55) | (37) |
| Swaps | 4,616,178 | (7,592) | (1,762) | 2,601,644 | (379) | (303) |

| | 2000 Notional Amount | 2000 Fair Value | 2000 Average Fair Value | 1999 Notional Amount | 1999 Fair Value | 1999 Average Fair Value |
|---|---|---|---|---|---|---|
| | GWH | (in thousands) | | GWH | (in thousands) | |
| **APCo Trading Assets** | | | | | | |
| Electric | | | | | | |
| Futures and Options-NYMEX (net) | - | $ - | $ - | 64 | $ 535 | $ 254 |
| Physicals | 45,406 | 2,246,952 | 757,757 | 19,953 | 165,624 | 150,377 |
| Options - OTC | 1,924 | 59,814 | 25,015 | 1,781 | 11,766 | 18,461 |
| Swaps | 3,652 | 51,470 | 18,387 | 51 | 112 | 90 |
| **Trading Liabilities** | | | | | | |
| Electric | | | | | | |
| Futures and Options-NYMEX (net) | - | $ - | $ - | - | $ - | $ - |
| Physicals | 45,994 | (2,271,026) | (747,567) | 21,461 | (154,364) | (144,876) |
| Options - OTC | 3,130 | (35,955) | (18,872) | 2,557 | (12,375) | (16,811) |
| Swaps | 3,562 | (44,855) | (14,103) | 52 | (103) | (85) |
| **KPCo Trading Assets** | | | | | | |
| Electric | | | | | | |
| Futures and Options-NYMEX (net) | - | $ - | $ - | 15 | $ 114 | $ 49 |
| Physicals | 10,779 | 533,781 | 179,999 | 4,707 | 39,074 | 35,477 |
| Options - OTC | 456 | 14,207 | 5,938 | 420 | 2,773 | 4,353 |
| Swaps | 867 | 12,227 | 4,368 | 12 | 26 | 21 |
| **Trading Liabilities** | | | | | | |
| Electric | | | | | | |
| Futures and Options-NYMEX (net) | - | $ - | $ - | - | $ - | $ - |
| Physicals | 10,919 | (539,465) | (177,581) | 5,063 | (36,422) | (34,180) |
| Options - OTC | 743 | (8,521) | (4,461) | 603 | (2,900) | (3,949) |
| Swaps | 846 | (10,656) | (3,350) | 12 | (24) | (20) |

| | 2000 Notional Amount GWH | 2000 Fair Value (in thousands) | 2000 Average Fair Value (in thousands) | 1999 Notional Amount GWH | 1999 Fair Value (in thousands) | 1999 Average Fair Value (in thousands) |
|---|---|---|---|---|---|---|
| **I&M** | | | | | | |
| **Trading Assets** | | | | | | |
| Electric | | | | | | |
| Futures and Options-NYMEX (net) | - | $ - | $ - | 43 | $ 340 | $ 171 |
| Physicals | 27,431 | 1,357,459 | 466,140 | 13,592 | 112,830 | 99,621 |
| Options - OTC | 1,162 | 36,139 | 15,464 | 1,213 | 8,010 | 12,125 |
| Swaps | 2,206 | 31,095 | 11,144 | 35 | 76 | 61 |
| **Trading Liabilities** | | | | | | |
| Electric | | | | | | |
| Futures and Options-NYMEX (net) | - | $ - | $ - | - | $ - | $ - |
| Physicals | 27,786 | (1,379,302) | (460,348) | 14,620 | (105,169) | (95,948) |
| Options - OTC | 1,891 | (25,807) | (13,031) | 1,742 | (8,391) | (11,010) |
| Swaps | 2,152 | (27,099) | (8,552) | 35 | (70) | (58) |
| **OPCo** | | | | | | |
| **Trading Assets** | | | | | | |
| Electric | | | | | | |
| Futures and Options-NYMEX (net) | - | $ - | $ - | 61 | $ 583 | $ 286 |
| Physicals | 36,080 | 1,786,137 | 639,632 | 18,753 | 155,507 | 146,395 |
| Options - OTC | 1,529 | 46,731 | 20,403 | 1,673 | 9,672 | 9,936 |
| Swaps | 2,902 | 41,788 | 16,172 | 48 | 987 | 967 |
| **Trading Liabilities** | | | | | | |
| Electric | | | | | | |
| Futures and Options-NYMEX (net) | - | $ - | $ - | - | $ - | $ - |
| Physicals | 36,547 | (1,802,295) | (627,137) | 20,171 | (143,440) | (135,015) |
| Options - OTC | 2,487 | (29,350) | (16,571) | 2,403 | (11,506) | (7,084) |
| Swaps | 2,830 | (37,398) | (13,447) | 49 | (1,846) | (1,829) |
| **CSPCo** | | | | | | |
| **Trading Assets** | | | | | | |
| Electric | | | | | | |
| Futures and Options-NYMEX (net) | - | $ - | $ - | 40 | $ 312 | $ 159 |
| Physicals | 24,221 | 1,198,835 | 420,090 | 12,503 | 103,794 | 91,570 |
| Options - OTC | 1,026 | 31,918 | 13,961 | 1,116 | 7,369 | 11,140 |
| Swaps | 1,948 | 27,461 | 9,914 | 32 | 70 | 56 |
| **Trading Liabilities** | | | | | | |
| Electric | | | | | | |
| Futures and Options-NYMEX (net) | - | $ - | $ - | - | $ - | $ - |
| Physicals | 24,535 | (1,211,580) | (414,198) | 13,449 | (96,748) | (88,194) |
| Options - OTC | 1,669 | (19,220) | (10,629) | 1,602 | (7,717) | (10,114) |
| Swaps | 1,900 | (23,932) | (7,599) | 32 | (64) | (53) |

| | 2000 | | |
|---|---|---|---|
| | Notional Amount GWH | Fair Value | Average Fair Value |
| | | (in thousands) | |
| CPL | | | |
| Trading Assets | | | |
| Electric Physicals | 31,040 | $547,437 | $ 210,189 |
| Trading Liabilities Electric Physicals | 31,442 | (555,628) | (211,482) |
| PSO | | | |
| Trading Assets | | | |
| Electric Physicals | 24,670 | 435,009 | 232,198 |
| Trading Liabilities Electric Physicals | 24,990 | (441,517) | (234,082) |
| SWEPCo | | | |
| Trading Assets Electric Physicals | 29,538 | 520,964 | 217,444 |
| Trading Liabilities Electric Physicals | 29,920 | (528,759) | (220,171) |
| WTU | | | |
| Trading Assets | | | |
| Electric Physicals | 9,821 | 173,118 | 58,048 |
| Trading Liabilities Electric Physicals | 9,948 | (175,708) | (58,071) |

There were no trading activities for CPL, PSO, SWEPCo, and WTU for the year ended 1999.

AEP routinely enters into exchange traded futures and options transactions for electricity and natural gas as part of its wholesale trading operations. These transactions are executed through brokerage accounts with brokers who are registered with the Commodity Futures Trading Commission. Brokers require cash or cash related instruments to be deposited on these accounts as margin calls against the customer's open position. The amount of these deposits at December 31, 2000 and 1999 was $95 million and $25 million, respectively.

*Credit and Risk Management* - In addition to market risk associated with price movements, AEP is also subject to the credit risk inherent in its risk management activities. Credit risk refers to the financial risk arising from commercial transactions and/or the intrinsic financial value of contractual agreements with trading counter parties, by which there exists a potential risk of non-performance. The AEP System has established and enforced credit policies that minimize or eliminate this risk. AEP accepts as counter parties to forwards, futures, and other derivative contracts primarily those entities that are classified as Investment Grade, or those that can be considered as such due to the effective placement of credit enhancements and/or collateral agreements. Investment Grade is the designation given to the four highest debt rating categories (i.e., AAA, AA, A, BBB) of the major rating services, e.g., ratings BBB- and above at Standard & Poor's and Baa3 and above at Moody's. When adverse market conditions have the potential to negatively affect a counter party's credit position, AEP will require further enhancements to mitigate risk. Since the formation of the trading business in July of 1997, AEP has not experienced a significant loss due to the credit risk; furthermore, AEP does not anticipate any future material effect on its results of operations, cash flow or financial condition as a result of counter party non-performance.

*Other Financial Instruments - Nuclear Trust Funds Recorded at Market Value* - The trust investments for decommission and SNF disposal, reported in other assets, are recorded at market value. At December 31, 2000 and 1999 the fair values of the trust investments were $873 million and $795 million, respectively, and had a cost basis of $768 million and $696 million, respectively. The change in market value in 2000, 1999, and 1998 was a net unrealized holding gain of $6 million, $18 million, and $32 million, respectively.

At December 31, 2000 and 1999 the fair value of CPL's trust investments for decommissioning were $94 million and $86 million, respectively, and had a cost basis of $70 million and $60 million, respectively. The change in market value for CPL was a net unrealized holding loss of $3 million in 2000 and a net unrealized holding gain of $10 million and $8 million in 1999 and 1998, respectively. At December 31, 2000 and 1999 the fair value of I&M's trust investments for decommissioning and SNF disposal were $779 million and $708 million, respectively, and had a cost basis of $698 million and $636 million, respectively. The change in market value for I&M in 2000, 1999, and 1998 was a net unrealized holding gain of $9 million, $8 million and $24 million, respectively.

CitiPower entered into several interest rate swap agreements for $425 million of borrowings under a credit facility. The swap agreements involve the exchange of floating-rate for fixed-rate interest payments. Interest is recognized currently based on the fixed rate of interest resulting from use of these swap agreements. Market risks arise from the movements in interest rates. If counter parties to an interest rate swap agreement were to default on contractual payments, CitiPower could be exposed to increased costs related to replacing the original agreement. However, CitiPower does not anticipate non-performance by any counter party to any interest rate swap in effect as of December 31, 2000. As of December 31, 2000, CitiPower was a party to interest rate swaps having an aggregate notional amount of $626 million, with $224 million maturing on December 31, 2003, and $201 million maturing on December 29, 2003, $201 million commencing on December 29, 2003 and maturing on December 30, 2005. The average fixed interest rate payable on the aggregate of the interest rate swaps is 5.84%. The average floating rate for interest rate swaps was 6.04% at December 31, 2000. The estimated fair value of the interest rate swaps, which represents the estimated amount CitiPower would receive to terminate the swaps at December 31, 2000, based on quoted interest rates, is a net receivable of less than a million dollars.

CitiPower entered into interest rate swap agreement for $112 million in January 2000, for the purpose of hedging a capital markets bond issue. The interest rate swap agreement exchanges a fixed-rate for a floating interest rate up to January 15, 2007. The $112 million interest rate swap agreement was terminated on December 18, 2000. The gain of $9 million earned upon termination of the swap agreement has been deferred and will be amortized through January 15, 2007.

The CSW UK Holdings Group (Group) entered into two currency swaps in 1996 in respect of two tranches of $200 million notes ("Yankee Bonds") repayable on August 1, 2001 and August 1, 2006. The swaps convert fixed rate semi-annual U.S. Dollar interest payments at 6.95% and 7.45% to fixed rate sterling. As a result of the swaps the effective fixed sterling interest rates, including fees, are 7.98% and 8.75%. The estimated fair value of these swaps at December 31, 2000 is a net payable of $1 million.

The Group also has an interest in two interest rate swaps entered into by its joint venture associate Power Asset Development Company Limited in 1998. The swaps convert floating rate interest payable on a $157 million bank project finance borrowing, maturing in 2021, to 6.00% fixed rate. The estimated fair value of these swaps at December 31, 2000 is a net payable of $3 million of which the Group's interest is $1 million.

In addition, at December 31, 2000, the Group has an interest in a currency swap and an interest rate swap entered into by another joint venture associate, South Coast Power Limited. The estimated fair value of these swaps is a net receivable of $3 million of which the Group's share is $1 million.

In accordance with the debt covenants included in the financing provisions of its credit facility, CitiPower must hedge at least 80% of its energy purchase requirements through energy trading derivative instruments entered into with market participants, predominantly generators. As of December 31, 2000, CitiPower had outstanding energy trading derivatives with a total contracted load of 10,144 GWH's. The maturities for these contracts range from three months to six years. Management's estimate of the fair value of these derivatives as of December 31, 2000 is $7 million in excess of net contract value.

SEEBOARD manages its energy purchase costs through energy trading derivative instruments entered into with market participants. The Company buys derivative instruments to hedge purchase costs only and does not enter into any speculative trades. As of December 31, 2000, SEEBOARD had outstanding energy trading derivatives with a total contracted volume of 14,059 GWH's excluding Medway Power Limited. These contracts have maturities in the range of 1 to 27 months. In addition SEEBOARD has a 15 year contract with Medway Power Limited which owns and operates a 675 MW combined cycle gas generating station. SEEBOARD also has a 37.5% equity interest in Medway Power Limited. There are 29,025 GWH remaining under the contract which has 10 years and 9 months to run.

Management's estimate of the fair value of these derivatives as of December 31, 2000 is $132 million below net contract value.

**16. Income Taxes:**

The details of AEP's consolidated income taxes as reported are as follows:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2000 | 1999 | 1998 |
| | | (in millions) | |
| Federal: | | | |
| Current | $ 766 | $308 | $492 |
| Deferred | (237) | 129 | (43) |
| Total | 529 | 437 | 449 |
| State: | | | |
| Current | 50 | 25 | 30 |
| Deferred | (9) | - | - |
| Total | 41 | 25 | 30 |
| International: | | | |
| Current | 6 | 3 | 14 |
| Deferred | 21 | 17 | 9 |
| Total | 27 | 20 | 23 |
| Total Income Tax as Reported | $ 597 | $482 | $502 |

The details of the registrant subsidiaries income taxes as reported are as follows:

| Year Ended December 31, 2000 | AEGCo | APCo | CPL (in thousands) | CSPCo | I&M |
|---|---|---|---|---|---|
| Charged (Credited) to Operating Expenses (net): | | | | | |
| Current | $ 8,746 | $129,165 | $ 89,403 | $120,494 | $ 134,796 |
| Deferred | (5,842) | 3,838 | 16,263 | (7,746) | (126,748) |
| Deferred Investment Tax Credits | - | (2,947) | (5,207) | (3,379) | (7,524) |
| Total | 2,904 | 130,056 | 100,459 | 109,369 | 524 |
| Charged (Credited) to Nonoperating Income (net): | | | | | |
| Current | (44) | 327 | (5,073) | 3,777 | 2,950 |
| Deferred | - | 4,764 | - | 3,683 | 1,569 |
| Deferred Investment Tax Credits | (3,396) | (1,968) | - | (103) | (330) |
| Total | (3,440) | 3,123 | (5,073) | 7,357 | 4,189 |
| Total Income Tax as Reported | $ (536) | $133,179 | $95,386 | $116,726 | $ 4,713 |

| Year Ended December 31, 2000 | KPCo | OPCo | PSO (in thousands) | SWEPCo | WTU |
|---|---|---|---|---|---|
| Charged (Credited) to Operating Expenses (net): | | | | | |
| Current | $17,878 | $259,608 | $11,597 | $16,073 | $ 6,774 |
| Deferred | 2,521 | (70,263) | 25,453 | 14,653 | 9,401 |
| Deferred Investment Tax Credits | (1,187) | (1,824) | (1,791) | (4,482) | (1,271) |
| Total | 19,212 | 187,521 | 35,259 | 26,244 | 14,904 |
| Charged (Credited) to Nonoperating Income (net): | | | | | |
| Current | (50) | 15,426 | (1,306) | (1,476) | (222) |
| Deferred | 1,244 | 4,307 | - | - | (1,237) |
| Deferred Investment Tax Credits | (65) | (1,575) | - | - | - |
| Total | 1,129 | 18,158 | (1,306) | (1,476) | (1,459) |
| Total Income Tax as Reported | $20,341 | $205,679 | $33,953 | $24,768 | $13,445 |

| Year Ended December 31, 1999 | AEGCo | APCo | CPL (in thousands) | CSPCo | I&M |
|---|---|---|---|---|---|
| Charged (Credited) to Operating Expenses (net): | | | | | |
| Current | $ 7,713 | $69,522 | $ 89,112 | $79,410 | $(67,368) |
| Deferred | (5,282) | 8,981 | 19,620 | 9,737 | 85,345 |
| Deferred Investment Tax Credits | - | (2,659) | (5,207) | (3,432) | (7,547) |
| Total | 2,431 | 75,844 | 103,525 | 85,715 | 10,430 |
| Charged (Credited) to Nonoperating Income (net): | | | | | |
| Current | (146) | (1,548) | (5,604) | (3,122) | 1,529 |
| Deferred | - | 4,052 | 318 | 744 | 382 |
| Deferred Investment Tax Credits | (3,448) | (2,313) | - | (562) | (605) |
| Total | (3,594) | 191 | (5,286) | (2,940) | 1,306 |
| Total Income Taxes as Reported | $(1,163) | $76,035 | $ 98,239 | $82,775 | $ 11,736 |

| Year Ended December 31, 1999 | KPCo | OPCo | PSO (in thousands) | SWEPCo | WTU |
|---|---|---|---|---|---|
| Charged (Credited) to Operating Expenses (net): | | | | | |
| Current | $14,897 | $135,540 | $20,777 | $ 60,169 | $ 3,328 |
| Deferred | 2,239 | 4,205 | 14,521 | (17,347) | 12,026 |
| Deferred Investment Tax Credits | (1,193) | (1,825) | (1,791) | (4,565) | (1,275) |
| Total | 15,943 | 137,920 | 33,507 | 38,257 | 14,079 |
| Charged (Credited) to Nonoperating Income (net): | | | | | |
| Current | (424) | (3,256) | (2,215) | (4,826) | 858 |
| Deferred | 357 | (539) | - | - | - |
| Deferred Investment Tax Credits | (99) | (1,633) | - | - | - |
| Total | (166) | (5,428) | (2,215) | (4,826) | 858 |
| Total Income Taxes as Reported | $15,777 | $132,492 | $31,292 | $ 33,431 | $14,937 |

| Year Ended December 31, 1998 | AEGCo | APCo | CPL (in thousands) | CSPCo | I&M |
|---|---|---|---|---|---|
| Charged (Credited) to Operating Expenses (net): | | | | | |
| Current | $(2,556) | $63,291 | $128,942 | $62,123 | $43,103 |
| Deferred | 5,544 | (143) | (8,328) | 17,612 | 21,073 |
| Deferred Investment Tax Credits | - | (2,671) | (3,858) | (3,498) | (7,593) |
| Total | 2,988 | 60,477 | 116,756 | 76,237 | 56,583 |
| Charged (Credited) to Nonoperating Income (net): | | | | | |
| Current | (45) | (4,902) | (2,204) | (3,795) | (594) |
| Deferred | - | (2,195) | - | (511) | (3,168) |
| Deferred Investment Tax Credits | (3,454) | (2,594) | - | (726) | (673) |
| Total | (3,499) | (9,691) | (2,204) | (5,032) | (4,435) |
| Total Income Taxes as Reported | $ (511) | $50,786 | $114,552 | $71,205 | $52,148 |

| Year Ended December 31, 1998 | KPCo | OPCo | PSO (in thousands) | SWEPCo | WTU |
|---|---|---|---|---|---|
| Charged (Credited) to Operating Expenses (net): | | | | | |
| Current | $10,788 | $120,932 | $52,587 | $ 64,463 | $28,542 |
| Deferred | 3,967 | 3,907 | (1,651) | (11,909) | (6,626) |
| Deferred Investment Tax Credits | (1,202) | (1,827) | (1,795) | (4,631) | (1,321) |
| Total | 13,553 | 123,012 | 49,141 | 47,923 | 20,595 |
| Charged (Credited) to Nonoperating Income (net): | | | | | |
| Current | (794) | (5,619) | (93) | (1,868) | (454) |
| Deferred | (360) | (865) | - | - | - |
| Deferred Investment Tax Credits | (213) | (1,698) | - | - | - |
| Total | (1,367) | (8,182) | (93) | (1,868) | (454) |
| Total Income Taxes as Reported | $12,186 | $114,830 | $49,048 | $ 46,055 | $20,141 |

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

| | Year Ended December 31, 2000 | 1999 (in millions) | 1998 |
|---|---|---|---|
| Net Income | $267 | $ 972 | $ 975 |
| Extraordinary Items (net of income tax $44 million in 2000 and $8 million in 1999) | 35 | 14 | - |
| Preferred Stock Dividends | 11 | 19 | 19 |
| Income Before Preferred Stock Dividends of Subsidiaries | 313 | 1,005 | 994 |
| Income Taxes | 597 | 482 | 502 |
| Pre-Tax Income | $910 | $1,487 | $1,496 |
| Income Tax on Pre-Tax Income at Statutory Rate *(35%)* | $319 | $520 | $524 |
| Increase (Decrease) in Income Tax Resulting from the Following Items: | | | |
| Depreciation | 77 | 71 | 67 |
| Corporate Owned Life Insurance | 247 | 2 | (16) |
| Foreign Tax Credits | (31) | (63) | (49) |
| Investment Tax Credits (net) | (36) | (38) | (37) |
| Merger Transaction Costs | 49 | - | - |
| State Income Taxes | 26 | 16 | 19 |
| International | 18 | 13 | 15 |
| Other | (72) | (39) | (21) |
| Total Income Taxes as Reported | $597 | $482 | $502 |
| Effective Income Tax Rate | 65.5% | 32.5% | 33.6% |

Shown below is a reconciliation for each AEP registrant subsidiary of the difference between the amount of federal income taxes computed by multiplying book income before federal income taxes by the statutory rate, and the amount of income taxes reported.

| Year Ended December 31, 2000 | AEGCo | APCo | CPL (in thousands) | CSPCo | I&M |
|---|---|---|---|---|---|
| Net Income (Loss) | $7,984 | $ 73,844 | $189,567 | $ 94,966 | $(132,032) |
| Extraordinary (Gains) Loss | | (1,066) | | 39,384 | |
| Income Tax Benefit | - | (7,872) | - | (14,148) | - |
| Income Taxes | (536) | 133,179 | 95,386 | 116,726 | 4,713 |
| Pre-Tax Income (Loss) | $7,448 | $198,085 | $284,953 | $236,928 | $(127,319) |
| Income Tax on Pre-Tax Income (Loss) at Statutory Rate *(35%)* | $ 2,607 | $ 69,330 | $99,733 | $ 82,925 | $(44,561) |
| Increase (Decrease) in Income Tax Resulting from the Following Items: | | | | | |
| Depreciation | 452 | 7,606 | 7,556 | 10,529 | 20,378 |
| Corporate Owned Life Insurance | - | 54,824 | - | 29,259 | 42,587 |
| Nuclear Fuel Disposal Costs | - | - | - | - | (3,957) |
| Allowance for Funds Used During Construction | (1,070) | - | - | - | (2,211) |
| Rockport Plant Unit 2 Investment Tax Credit | 374 | - | - | - | - |
| Removal Costs | - | (1,197) | - | - | - |
| Investment Tax Credits (net) | (3,396) | (4,915) | (5,207) | (3,482) | (7,854) |
| State Income Taxes | 784 | 9,950 | 2,296 | 89 | 6,004 |
| Other | (287) | (2,419) | (8,992) | (2,594) | (5,673) |
| Total Income Taxes as Reported | $ (536) | $133,179 | $95,386 | $116,726 | $ 4,713 |
| Effective Income Tax Rate | N.M. | 67.2% | 33.5% | 49.3% | N.M. |

| Year Ended December 31, 2000 | KPCo | OPCo | PSO (in thousands) | SWEPCo | WTU |
|---|---|---|---|---|---|
| Net Income | $20,763 | $ 83,737 | $ 66,663 | $72,672 | $27,450 |
| Extraordinary Loss | | 40,157 | | | |
| Income Tax Benefit | - | (21,281) | - | - | - |
| Income Taxes | 20,342 | 205,679 | 33,953 | 24,768 | 13,445 |
| Pre-Tax Income | $41,105 | $308,292 | $100,616 | $97,440 | $40,895 |
| Income Tax on Pre-Tax Income at Statutory Rate *(35%)* | $14,387 | $107,903 | $35,216 | $ 34,104 | $14,313 |
| Increase (Decrease) in Income Tax Resulting from the Following Items: | | | | | |
| Depreciation | 1,827 | 27,577 | - | - | 1,204 |
| Corporate Owned Life Insurance | 5,149 | 84,453 | - | - | - |
| Nuclear Fuel Disposal Costs | - | - | - | - | - |
| Allowance for Funds Used During Construction | - | - | - | - | - |
| Rockport Plant Unit 2 Investment Tax Credit | - | - | - | - | - |
| Removal Costs | (420) | - | - | - | - |
| Investment Tax Credits (net) | (1,252) | (3,398) | (1,791) | (4,482) | (1,271) |
| State Income Taxes | 1,597 | (1,988) | 3,037 | 1,650 | - |
| Other | (946) | (8,868) | (2,509) | (6,504) | (801) |
| Total Income Taxes as Reported | $20,342 | $205,679 | $33,953 | $ 24,768 | $13,445 |
| Effective Income Tax Rate | 49.5% | 66.8% | 33.8% | 25.4% | 32.9% |

| Year Ended December 31, 1999 | AEGCo | APCo | CPL (in thousands) | CSPCo | I&M |
|---|---|---|---|---|---|
| Net Income | $ 6,195 | $120,492 | $182,201 | $150,270 | $32,776 |
| Extraordinary Loss | | | 8,488 | | |
| Income Tax Benefit | - | - | (2,971) | - | - |
| Income Taxes | (1,163) | 76,035 | 98,239 | 82,775 | 11,736 |
| Pre-Tax Income | $ 5,032 | $196,527 | $285,957 | $233,045 | $44,512 |
| Income Tax on Pre-Tax Income at Statutory Rate *(35%)* | $ 1,762 | $ 68,785 | $100,085 | $ 81,566 | $15,580 |
| Increase (Decrease) in Income Tax Resulting from the Following Items: | | | | | |
| Depreciation | 446 | 12,593 | 7,981 | 8,846 | 19,966 |
| Corporate Owned Life Insurance | - | - | - | - | 594 |
| Nuclear Fuel Disposal Costs | - | - | - | - | (3,347) |
| Allowance for Funds Used During Construction | (1,069) | - | - | - | (2,174) |
| Rockport Plant Unit 2 Investment Tax Credit | 374 | - | - | - | - |
| Removal Costs | - | (3,220) | - | - | - |
| Investment Tax Credits (net) | (3,448) | (4,972) | (5,207) | (3,994) | (8,152) |
| State Income Taxes | 467 | 3,305 | 6,965 | 58 | (4,635) |
| Other | 305 | (456) | (11,585) | (3,701) | (6,096) |
| Total Income Taxes as Reported | $(1,163) | $ 76,035 | $ 98,239 | $ 82,775 | $11,736 |
| Effective Income Tax Rate | N.M. | 38.7% | 34.4% | 35.6% | 26.4% |

| Year Ended December 31, 1999 | KPCo | OPCo | PSO | SWEPCo | WTU |
|---|---|---|---|---|---|
| | | | (in thousands) | | |
| Net Income | $25,430 | $212,157 | $61,508 | $83,194 | $26,406 |
| Extraordinary Loss | | | | 4,632 | 8,402 |
| Income Tax Benefit | - | - | - | (1,621) | (2,941) |
| Income Taxes | 15,777 | 132,492 | 31,292 | 33,431 | 14,937 |
| Pre-Tax Income | $41,207 | $344,649 | $92,800 | $119,636 | $46,804 |
| Income Tax on Pre-Tax Income at Statutory Rate *(35%)* | $14,423 | $120,628 | $ 32,480 | $ 41,873 | $16,382 |
| Increase (Decrease) in Income Tax Resulting from the Following Items: | | | | | |
| Depreciation | 1,843 | 17,517 | - | - | 1,120 |
| Corporate Owned Life Insurance | - | 198 | - | - | - |
| Removal Costs | (420) | - | - | - | - |
| Investment Tax Credits (net) | (1,292) | (3,458) | (1,791) | (4,565) | (1,275) |
| State Income Taxes | 1,809 | 1,090 | 3,054 | 2,924 | - |
| Other | (586) | (3,483) | (2,451) | (6,801) | (1,290) |
| Total Income Taxes as Reported | $15,777 | $132,492 | $ 31,292 | $ 33,431 | $14,937 |
| Effective Income Tax Rate | 38.3% | 38.5% | 33.8% | 28.0% | 32.0% |

| Year Ended December 31, 1998 | AEGCo | APCo | CPL | CSPCo | I&M |
|---|---|---|---|---|---|
| | | | (in thousands) | | |
| Net Income | $ 8,946 | $ 93,330 | $161,511 | $133,044 | $ 96,628 |
| Income Taxes | (511) | 50,786 | 114,552 | 71,205 | 52,148 |
| Pre-Tax Income | $ 8,435 | $144,116 | $276,063 | $204,249 | $148,776 |
| Income Tax on Pre-Tax Book Income at Statutory Rate *(35%)* | $ 2,953 | $ 50,441 | $ 96,623 | $ 71,488 | $ 52,072 |
| Increase (Decrease) in Income Tax Resulting from the Following Items: | | | | | |
| Depreciation | 1,105 | 11,667 | 8,170 | 8,604 | 17,257 |
| Corporate Owned Life Insurance | - | (4,212) | - | - | (3,263) |
| Allowance for Funds Used During Construction | (1,070) | - | - | - | (2,184) |
| Rockport Plant Unit 2 Investment Tax Credits | 374 | - | - | - | - |
| Nuclear Fuel Disposal Costs | - | - | - | - | (3,397) |
| Removal Costs | - | (4,200) | - | - | - |
| Investment Tax Credits (net) | (3,454) | (5,265) | (3,858) | (4,224) | (8,266) |
| State Income Taxes | (203) | 4,449 | - | 1 | 3,209 |
| Mirror CWIP | - | - | 10,055 | - | - |
| Other | (216) | (2,094) | 3,562 | (4,664) | (3,280) |
| Total Income Taxes as Reported | $ (511) | $ 50,786 | $114,552 | $ 71,205 | $52,148 |
| Effective Income Tax Rate | N.M. | 35.3% | 41.5% | 34.9% | 35.1% |

| Year Ended December 31, 1998 | KPCo | OPCo | PSO | SWEPCo | WTU |
|---|---|---|---|---|---|
| | | | (in thousands) | | |
| Net Income | $21,676 | $209,925 | $ 76,909 | $ 97,994 | $37,725 |
| Income Taxes | 12,186 | 114,830 | 49,048 | 46,055 | 20,141 |
| Pre-Tax Income | $33,862 | $324,755 | $125,957 | $144,049 | $57,866 |
| Income Tax on Pre-Tax Book Income at Statutory Rate *(35%)* | $11,852 | $113,665 | $ 44,085 | $ 50,418 | $20,253 |
| Increase (Decrease) in Income Tax Resulting from the Following Items: | | | | | |
| Depreciation | 1,633 | 16,693 | - | - | 964 |
| Corporate Owned Life Insurance | - | (5,238) | - | - | - |
| Removal Costs | (840) | - | - | - | - |
| Investment Tax Credits (net) | (1,415) | (3,525) | (1,795) | (4,631) | (1,321) |
| State Income Taxes | 1,560 | 1,782 | 4,478 | 3,308 | - |
| Other | (604) | (8,547) | 2,280 | (3,040) | 245 |
| Total Income Taxes as Reported | $12,186 | $114,830 | $ 49,048 | $ 46,055 | $20,141 |
| Effective Income Tax Rate | 36.0% | 35.4% | 39.0% | 32.0% | 34.9% |

The following tables show the elements of the net deferred tax liability and the significant temporary differences for AEP Consolidated and each registrant subsidiary:

| | December 31, 2000 | December 31, 1999 |
|---|---|---|
| | (in millions) | |
| Deferred Tax Assets | $ 1,248 | $ 1,241 |
| Deferred Tax Liabilities | (6,123) | (6,391) |
| Net Deferred Tax Liabilities | $(4,875) | $(5,150) |
| Property Related Temporary Differences | $(3,935) | $(4,109) |
| Amounts Due From Customers For Future Federal Income Taxes | (415) | (437) |
| Deferred State Income Taxes | (251) | (220) |
| Regulatory Assets Designated for Securitization | (332) | (332) |
| All Other (net) | 58 | (52) |
| Net Deferred Tax Liabilities | $(4,875) | $(5,150) |

| December 31, 2000 | AEGCo | APCo | CPL | CSPCo | I&M |
|---|---|---|---|---|---|
| | | | (in thousands) | | |
| Deferred Tax Assets | $ 81,480 | $ 178,487 | $ 67,184 | $ 88,198 | $ 342,900 |
| Deferred Tax Liabilities | (114,408) | (860,961) | (1,309,981) | (510,957) | (830,845) |
| Net Deferred Tax Liabilities | $ (32,928) | $(682,474) | $(1,242,797) | $(422,759) | $(487,945) |
| Property Related Temporary Differences | $ (78,113) | $(510,950) | $ (773,454) | $(343,045) | $(324,198) |
| Amounts Due From Customers For Future Federal Income Taxes | 10,317 | (95,639) | (72,426) | (79,959) | (55,218) |
| Deferred State Income Taxes | (5,478) | (86,351) | - | - | (69,982) |
| Net Deferred Gain on Sale and Leaseback-Rockport Plant Unit 2 | 42,766 | - | - | - | 28,454 |
| Accrued Nuclear Decommissioning Expense | - | - | - | - | 34,702 |
| Deferred Fuel and Purchased Power | - | - | - | - | (39,395) |
| Deferred Cook Plant Restart Costs | - | - | - | - | (42,000) |
| Nuclear Fuel | - | - | - | - | (28,319) |
| Regulatory Assets Designated for Securitization | - | - | (332,198) | - | - |
| All Other (net) | (2,420) | 10,466 | (64,719) | 245 | 8,011 |
| Net Deferred Tax Liabilities | $ (32,928) | $(682,474) | $(1,242,797) | $(422,759) | $(487,945) |

| December 31, 2000 | KPCo | OPCo | PSO | SWEPCo | WTU |
|---|---|---|---|---|---|
| | | | (in thousands) | | |
| Deferred Tax Assets | $ 32,807 | $ 330,878 | $ 60,010 | $ 47,615 | $ 16,604 |
| Deferred Tax Liabilities | (198,742) | (952,819) | (372,070) | (446,819) | (173,642) |
| Net Deferred Tax Liabilities | $(165,935) | $(621,941) | $(312,060) | $(399,204) | $(157,038) |
| Property Related Temporary Differences | $(116,109) | $(586,039) | $(313,248) | $(375,427) | $(150,264) |
| Amounts Due From Customers For Future Federal Income Taxes | (19,680) | (110,908) | 11,082 | (6,015) | 4,723 |
| Deferred State Income Taxes | (29,695) | (14,282) | (36,487) | - | - |
| Deferred Fuel and Purchased Power | - | (116,224) | - | - | - |
| Provision for Mine Shutdown Costs | - | 63,995 | - | - | - |
| Postretirement Benefits | - | 93,306 | - | - | - |
| All Other (net) | (451) | 48,211 | 26,593 | (17,762) | (11,497) |
| Net Deferred Tax Liabilities | $(165,935) | $(621,941) | $(312,060) | $(399,204) | $(157,038) |

| December 31, 1999 | AEGCo | APCo | CPL | CSPCo | I&M |
|---|---|---|---|---|---|
| | | | (in thousands) | | |
| Deferred Tax Assets | $ 85,392 | $ 173,038 | $ 99,426 | $ 79,510 | $ 231,329 |
| Deferred Tax Liabilities | (121,892) | (844,955) | (1,334,601) | (527,117) | (853,486) |
| Net Deferred Tax Liabilities | $ (36,500) | $(671,917) | $(1,234,175) | $(447,607) | $(622,157) |
| Property Related Temporary Differences | $ (84,149) | $(510,143) | $ (798,381) | $(352,805) | $(436,162) |
| Amounts Due From Customers For Future Federal Income Taxes | 11,283 | (109,846) | (74,328) | (85,078) | (61,311) |
| Deferred State Income Taxes | (5,970) | (76,073) | - | - | (61,700) |
| Net Deferred Gain on Sale and Leaseback-Rockport Plant Unit 2 | 44,716 | - | - | - | 29,752 |
| Accrued Nuclear Decommissioning Expense | - | - | - | - | 32,097 |
| Deferred Fuel and Purchased Power | - | - | - | - | (52,713) |
| Deferred Cook Plant Restart Costs | - | - | - | - | (56,000) |
| Nuclear Fuel | - | - | - | - | (27,512) |
| Regulatory Assets Designated for Securitization | - | - | (332,198) | - | - |
| All Other (net) | (2,380) | 24,145 | (29,268) | (9,724) | 11,392 |
| Net Deferred Tax Liabilities | $ (36,500) | $(671,917) | $(1,234,175) | $(447,607) | $(622,157) |

| December 31, 1999 | KPCo | OPCo | PSO (in thousands) | SWEPCo | WTU |
|---|---|---|---|---|---|
| Deferred Tax Assets | $ 32,186 | $ 234,826 | $ 68,488 | $ 79,056 | $ 26,916 |
| Deferred Tax Liabilities | (197,193) | (911,286) | (350,404) | (455,560) | (175,908) |
| Net Deferred Tax Liabilities | $(165,007) | $(676,460) | $(281,916) | $(376,504) | $(148,992) |
| Property Related Temporary Differences | $(114,903) | $(599,863) | $(308,497) | $(389,680) | $(153,027) |
| Amounts Due From Customers For Future Federal Income Taxes | (19,616) | (108,185) | 12,697 | (3,366) | 4,569 |
| Deferred State Income Taxes | (32,715) | (22,124) | (13,001) | - | - |
| Deferred Fuel and Purchase Power | - | (62,832) | - | - | - |
| Provision for Mine Shutdown Costs | - | 33,105 | - | - | - |
| Postretirement Benefits | - | 44,483 | - | - | - |
| All Other (net) | 2,227 | 38,956 | 26,885 | 16,542 | (534) |
| Net Deferred Tax Liabilities | $(165,007) | $(676,460) | $(281,916) | $(376,504) | $(148,992) |

The AEP System has settled with the IRS all issues from the audits of its consolidated federal income tax returns for the years prior to 1991. Returns for the years 1991 through 1999 are presently being audited by the IRS. Management is not aware of any issues for open tax years that upon final resolution are expected to have a material adverse effect on results of operations.

## 17. Supplementary Information:

| | Year Ended December 31, 2000 | 1999 (in millions) | 1998 |
|---|---|---|---|
| AEP Consolidated Purchased Power - Ohio Valley Electric Corporation (44.2% owned by AEP System) | $86 | $64 | $43 |
| Cash was paid for: | | | |
| Interest (net of capitalized amounts) | $842 | $979 | $859 |
| Income Taxes | $449 | $270 | $540 |
| Noncash Investing and Financing Activities: | | | |
| Acquisitions under Capital Leases | $118 | $80 | $119 |
| Assumption of Liabilities Related to Acquisitions | - | - | $152 |

The amounts of power purchased by the registrant subsidiaries from Ohio Valley Electric Corporation, which is 44.2% owned by the AEP System, for the years ended December 31, 2000, 1999, and 1998 were:

| Year Ended December 31, | APCo | CSPCo (in thousands) | I&M | OPCo |
|---|---|---|---|---|
| 2000 | $30,998 | $8,706 | $15,204 | $31,134 |
| 1999 | 21,774 | 6,006 | 10,227 | 25,623 |
| 1998 | 10,388 | 5,947 | 14,271 | 12,006 |

## 18. Leases:

Leases of property, plant and equipment are for periods up to 35 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 operating expenses in accordance with rate-making treatment. The components of rental costs are as follows:

| Year Ended December 31, 2000 | AEP | AEGCo | APCo | CSPCo | I&M | KPCo | OPCo |
|---|---|---|---|---|---|---|---|
| | | | (in thousands) | | | | |
| Lease Payments on Operating Leases | $216,000 | $73,858 | $ 7,128 | $ 7,683 | $ 81,446 | $1,978 | $51,981 |
| Amortization of Capital Leases | 121,000 | 281 | 13,900 | 7,776 | 26,341 | 3,931 | 37,280 |
| Interest on Capital Leases | 38,000 | 55 | 3,930 | 2,690 | 10,908 | 1,054 | 9,584 |
| Total Lease Rental Costs | $375,000 | $74,194 | $24,958 | $18,149 | $118,695 | $6,963 | $98,845 |

| Year Ended December 31, 1999 | AEP | AEGCo | APCo | CSPCo | I&M | KPCo | OPCo |
|---|---|---|---|---|---|---|---|
| | | | (in thousands) | | | | |
| Lease Payments on Operating Leases | $247,000 | $74,269 | $ 5,647 | $ 5,687 | $ 81,611 | $ 199 | $ 60,026 |
| Amortization of Capital Leases | 97,000 | 364 | 13,749 | 7,427 | 11,320 | 4,299 | 35,622 |
| Interest on Capital Leases | 35,000 | 64 | 4,267 | 2,720 | 9,338 | 1,162 | 9,552 |
| Total Lease Rental Costs | $379,000 | $74,697 | $23,663 | $15,834 | $102,269 | $5,660 | $105,200 |

| Year Ended December 31, 1998 | AEP | AEGCo | APCo | CSPCo | I&M | KPCo | OPCo |
|---|---|---|---|---|---|---|---|
| | | | (in thousands) | | | | |
| Lease Payments on Operating Leases | $257,000 | $76,387 | $ 7,047 | $ 8,107 | $ 88,297 | $ 931 | $ 59,141 |
| Amortization of Capital Leases | 91,000 | 560 | 13,561 | 6,530 | 10,717 | 4,265 | 36,585 |
| Interest on Capital Leases | 37,000 | 97 | 3,541 | 2,626 | 10,302 | 1,173 | 14,309 |
| Total Lease Rental Costs | $385,000 | $77,044 | $24,149 | $17,263 | $109,316 | $6,369 | $110,035 |

CPL, PSO, SWEPCo and WTU do not have any operating leases.

Property, plant and equipment under capital leases and related obligations recorded on the Consolidated Balance Sheets are as follows:

| Year Ended December 31, 2000 | AEP | AEGCo | APCo | CSPCo | I&M | KPCo | OPCo |
|---|---|---|---|---|---|---|---|
| | | | (in thousands) | | | | |
| Property, Plant and Equipment Under Capital Leases | | | | | | | |
| Production | $ 42,000 | $2,017 | $ 6,276 | $ 2 | $ 7,023 | $ 1,730 | $ 24,709 |
| Distribution | 151,000 | | | | 14,595 | | |
| Other: | | | | | | | |
| Nuclear Fuel (net of amortization) | 90,000 | | | | 89,872 | | |
| Mining Assets and Other | 619,000 | 177 | 93,437 | $68,352 | 97,383 | 22,072 | 200,308 |
| Total Property, Plant and Equipment | 902,000 | 2,194 | 99,713 | 68,354 | 208,873 | 23,802 | 225,017 |
| Accumulated Amortization | 288,000 | 1,603 | 36,553 | 25,422 | 45,700 | 9,618 | 108,436 |
| Net Property, Plant and Equipment Under Capital Leases | $614,000 | $ 591 | $63,160 | $42,932 | $163,173 | $14,184 | $116,581 |
| Obligations Under Capital Leases: | | | | | | | |
| Noncurrent Liability | $419,000 | $ 358 | $50,350 | $35,199 | $ 62,325 | $11,091 | $ 83,866 |
| Liability Due Within One Year | 195,000 | 233 | 12,810 | 7,733 | 100,848 | 3,093 | 32,715 |
| Total Obligations Under Capital Leases | $614,000 | $ 591 | $63,160 | $42,932 | $163,173 | $14,184 | $116,581 |

| Year Ended December 31, 1999 | AEP | AEGCo | APCo | CSPCo (in thousands) | I&M | KPCo | OPCo |
|---|---|---|---|---|---|---|---|
| Property, Plant and Equipment Under Capital Leases | | | | | | | |
| Production | $ 46,000 | $2,350 | $ 8,354 | | $ 8,348 | $ 2,022 | $ 24,428 |
| Distribution | 106,000 | | | | 14,645 | | |
| Other: | | | | | | | |
| Nuclear Fuel (net of amortization) | 108,000 | | | | 108,140 | | |
| Mining Assets and Other | 612,000 | 226 | 93,053 | $63,386 | 99,367 | 24,225 | 205,209 |
| Total Property, Plant and Equipment | 872,000 | 2,576 | 101,407 | 63,386 | 230,500 | 26,247 | 229,637 |
| Accumulated Amortization | 262,000 | 1,708 | 36,762 | 23,116 | 42,535 | 11,106 | 93,094 |
| Net Property, Plant and Equipment Under Capital Leases | $610,000 | $ 868 | $ 64,645 | $40,270 | $187,965 | $15,141 | $136,543 |
| Obligations Under Capital Leases: | | | | | | | |
| Noncurrent Liability | $510,000 | $ 592 | $ 52,009 | $33,031 | $176,893 | $11,830 | $102,259 |
| Liability Due Within One Year | 100,000 | 276 | 12,636 | 7,239 | 11,072 | 3,311 | 34,284 |
| Total Obligations Under Capital Leases | $610,000 | $ 868 | $ 64,645 | $40,270 | $187,965 | $15,141 | $136,543 |

Properties under operating leases and related obligations are not included in the Consolidated Balance Sheets.

CPL, PSO, SWEPCo and WTU do not lease property, plant and equipment under capital leases.

Future minimum lease payments consisted of the following at December 31, 2000:

| Capital (a) | AEP | AEGCo | APCo | CSPCo (in thousands) | I&M | KPCo | OPCo |
|---|---|---|---|---|---|---|---|
| 2001 | $129,000 | $255 | $16,528 | $10,480 | $ 14,620 | $ 3,929 | $ 39,733 |
| 2002 | 99,000 | 217 | 15,526 | 9,426 | 13,535 | 3,501 | 21,332 |
| 2003 | 81,000 | 133 | 12,872 | 7,677 | 11,336 | 2,661 | 19,004 |
| 2004 | 63,000 | 20 | 10,336 | 6,331 | 9,397 | 2,004 | 15,445 |
| 2005 | 48,000 | 6 | 7,027 | 5,397 | 7,053 | 1,609 | 11,746 |
| Later Years | 397,000 | 1 | 13,748 | 15,376 | 25,427 | 3,417 | 38,710 |
| Total Future Minimum Lease Payments | 817,000(a) | 632 | 76,037 | 54,687 | 81,368 | 17,121 | 145,970 |
| Less Estimated Interest Element | 293,000 | 41 | 12,876 | 11,755 | 8,067 | 2,937 | 29,389 |
| Estimated Present Value of Future Minimum Lease Payments | 524,000 | $591 | $63,161 | $42,932 | 73,301 | $14,184 | $116,581 |
| Unamortized Nuclear Fuel | 90,000 | | | | 89,872 | | |
| Total | $614,000 | | | | $163,173 | | |

(a) Minimum lease payments do not include nuclear fuel payments. The payments are paid in proportion to heat produced and carrying charges on the unamortized nuclear fuel balance. There are no minimum lease payment requirements for leased nuclear fuel.

| Noncancellable Operating Leases | AEP | AEGCo | APCo | CSPCo (in thousands) | I&M | KPCo | OPCo |
|---|---|---|---|---|---|---|---|
| 2001 | $ 244,000 | $ 73,854 | $ 726 | $ 4,314 | $ 99,249 | $ 29 | $ 62,560 |
| 2002 | 236,000 | 73,854 | 425 | 774 | 97,551 | 26 | 61,787 |
| 2003 | 235,000 | 73,854 | 412 | 735 | 97,385 | 23 | 61,109 |
| 2004 | 235,000 | 73,854 | 412 | 735 | 96,467 | 21 | 61,229 |
| 2005 | 243,000 | 73,854 | 412 | 735 | 95,201 | 21 | 71,304 |
| Later Years | 3,090,000 | 1,255,518 | 2,888 | 2,820 | 1,434,570 | 232 | 386,629 |
| Total Future Minimum Lease Payments | $4,283,000 | $1,624,788 | $5,275 | $10,113 | $1,920,423 | $352 | $704,618 |

## 19. Lines of Credit and Factoring of Receivables:

The AEP System uses short-term debt, primarily commercial paper, to meet fluctuations in working capital requirements and other interim capital needs. AEP has established a money pool to coordinate short-term borrowings for certain subsidiaries, including AEGCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo and WTU, and also incurs borrowings outside the money pool for other subsidiaries. As of December 31, 2000, AEP had revolving credit facilities totaling $3.5 billion to backup its commercial paper program. At December 31, 2000, AEP had $2.7 billion outstanding in short-term borrowings. The maximum amount of such short-term borrowings outstanding during the year, which had a weighted average interest rate for the year of 7.5%, was $2.7 billion during December 2000.

The registrant subsidiaries incurred interest expense for amounts borrowed from the AEP money pool as follows

| | Year Ended December 31, 2000 | 1999 | 1998 |
|---|---|---|---|
| | (in millions) | | |
| CPL | $16.9 | $14.1 | $8.8 |
| CSPCo | 1.4 | - | - |
| I&M | 0.8 | - | - |
| KPCo | - | - | - |
| OPCo | 9.2 | - | - |
| PSO | 7.5 | 2.0 | 1.0 |
| SWEPCo | 4.2 | 4.7 | 1.8 |
| WTU | 2.7 | 0.6 | 0.3 |

Interest income earned from amounts advanced to the AEP money pool by the registrant subsidiaries were:

| | Year Ended December 31, 2000 | 1999 | 1998 |
|---|---|---|---|
| | (in millions) | | |
| CSPCo | $ 1.1 | $ - | $ - |
| I&M | 9.0 | - | - |
| KPCo | 1.8 | - | - |
| OPCo | 3.4 | - | - |
| PSO | - | - | 0.6 |
| SWEPCo | - | 0.1 | 0.1 |
| WTU | - | 0.2 | 0.4 |

AEP Credit, which does not participate in the money pool, issues commercial paper on a stand-alone basis. At December 31, 2000, AEP Credit had a $2.0 billion unsecured revolving credit agreement to back up its commercial paper program, which had $1.2 billion outstanding. The maximum amount of such commercial paper outstanding during the year, which had a weighted average interest rate for the year of 6.6% was $1.5 billion during September 2000.

Outstanding short-term debt for AEP Consolidated consisted of:

| | December 31, 2000 | 1999 |
|---|---|---|
| | (in millions) | |
| Balance Outstanding: | | |
| Notes Payable | $ 193 | $ 232 |
| Commercial Paper | 4,140 | 2,780 |
| Total | $4,333 | $3,012 |

In 2000 APCo did not participate in AEP's money pool. At December 31, 2000 and 1999, APCo had issued commercial paper in the amounts of $191.5 million and $123.5 million, respectively. At December 31, 2000, the weighted average interest rate for APCo's commercial paper borrowings was 8.24%. In January 2001 APCo became a participant in AEP's money pool and retired all outstanding short-term debt.

AEP Credit factors electric customer accounts receivable for affiliated operating companies and unaffiliated companies. AEP Credit issues commercial paper on a stand alone basis and does not participate in the money pool. In June 2000 the factoring of customer accounts receivable for affiliated companies was expanded as a result of the merger.

Under the factoring arrangement the registrant subsidiaries (excluding AEGCo and APCo) sell without recourse certain of their customer accounts receivable and accrued utility revenue balances to AEP Credit and are charged a fee based on AEP Credit financing costs, uncollectible accounts experience for each company's receivables and administrative costs. The costs of factoring customer accounts receivable is reported as an operating expense. At December 31, 2000, the amount of factored accounts receivable and accrued utility revenues for each registrant subsidiary was as follows:

| Company | (in millions) |
|---|---|
| CPL | $153 |
| CSPCo | 116 |
| I&M | 103 |
| KPCo | 30 |
| OPCo | 104 |
| PSO | 108 |
| SWEPCo | 91 |
| WTU | 52 |

The fees paid by the registrant subsidiaries to AEP Credit for factoring customer accounts receivable were:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2000 | 1999 | 1998 |
| | | (in millions) | |
| CPL | $15.7 | $14.7 | $12.8 |
| CSPCo | 10.8 | - | - |
| I&M | 6.8 | - | - |
| KPCo | 1.9 | - | - |
| OPCo | 8.4 | - | - |
| PSO | 8.3 | 6.5 | 7.7 |
| SWEPCo | 9.2 | 9.3 | 9.1 |
| WTU | 4.0 | 3.5 | 3.7 |

**20. Unaudited Quarterly Financial Information:**

The unaudited quarterly financial information for AEP Consolidated follows:

| (In Millions - Except Per Share Amounts) | 2000 Quarterly Periods Ended March 31 | June 30 | Sept. 30 | Dec. 31 |
|---|---|---|---|---|
| Operating Revenues | $3,021 | $3,169 | $3,915 | $3,589 |
| Operating Income | 428 | 308 | 873 | 417 |
| Income (Loss) Before Extraordinary Items | 140 | (18) | 403 | (223) |
| Net Income (Loss) | 140 | (9) | 359 | (223) |
| Earnings (Loss) per Share | 0.43 | (0.03) | 1.11 | (0.68) |

Fourth quarter 2000 earnings decreased $415 million from the prior year. The decrease was primarily due to various unfavorable items including: a ruling disallowing interest deductions claimed by AEP relating to its COLI program of $319 million; $35 million of the Cook Plant restart costs; and a $30 million writedown for the proposed sale of Yorkshire. Additionally, the fourth quarter of 1999 includes a $33 million gain on the sale of Sweeney in October.

| (In Millions - Except Per Share Amounts) | 1999 Quarterly Periods Ended March 31 | June 30 | Sept. 30 | Dec. 31 |
|---|---|---|---|---|
| Operating Revenues | $2,902 | $2,963 | $3,528 | $3,014 |
| Operating Income | 525 | 552 | 802 | 446 |
| Income Before Extraordinary Items | 195 | 190 | 403 | 198 |
| Net Income | 195 | 190 | 395 | 192 |
| Earnings per Share | 0.61 | 0.59 | 1.23 | 0.60 |

The unaudited quarterly financial information for each AEP registrant subsidiary follows:

| Quarterly Periods Ended | AEGCo | APCo | CPL (in thousands) | CSPCo | I&M |
|---|---|---|---|---|---|
| **2000** | | | | | |
| **March 31** | | | | | |
| Operating Revenues | $56,866 | $455,595 | $316,328 | $298,306 | $343,986 |
| Operating Income | 2,395 | 78,246 | 38,650 | 44,124 | (15,251) |
| Income (Loss) Before Extraordinary Items | 2,445 | 47,664 | 8,139 | 27,471 | (36,553) |
| Net Income (Loss) | 2,445 | 47,664 | 8,139 | 27,471 | (36,553) |
| **June 30** | | | | | |
| Operating Revenues | $56,928 | $430,000 | $437,911 | $330,914 | $362,272 |
| Operating Income | 1,746 | 58,208 | 95,717 | 50,798 | (18,599) |
| Income (Loss) Before Extraordinary Items | 1,653 | 30,240 | 67,553 | 35,335 | (39,181) |
| Net Income (Loss) | 1,653 | 39,178 | 67,553 | 35,335 | (39,181) |
| **September 30** | | | | | |
| Operating Revenues | $55,658 | $475,092 | $601,369 | $386,583 | $423,217 |
| Operating Income | 2,209 | 65,750 | 120,653 | 83,562 | 36,056 |
| Income Before Extraordinary Items | 1,972 | 36,112 | 89,974 | 65,542 | 15,190 |
| Net Income | 1,972 | 36,112 | 89,974 | 40,306 | 15,190 |
| **December 31** | | | | | |
| Operating Revenues | $59,064 | $499,478 | $415,569 | $340,605 | $419,001 |
| Operating Income | 2,074 | (1,050) | 52,078 | 17,393 | (36,908) |
| Income (Loss) Before Extraordinary Items | 1,914 | (49,110) | 23,901 | (8,146) | (71,488) |
| Net Income (Loss) | 1,914 | (49,110) | 23,901 | (8,146) | (71,488) |

| Quarterly Periods Ended | KPCo | OPCo | PSO (in thousands) | SWEPCo | WTU |
|---|---|---|---|---|---|
| **2000** | | | | | |
| **March 31** | | | | | |
| Operating Revenues | $ 97,204 | $545,411 | $161,329 | $212,156 | $ 96,535 |
| Operating Income | 15,557 | 65,113 | 10,860 | 22,731 | 9,781 |
| Income Before Extraordinary Items | 8,052 | 46,216 | 1,165 | 7,663 | 3,833 |
| Net Income | 8,052 | 46,216 | 1,165 | 7,663 | 3,833 |
| **June 30** | | | | | |
| Operating Revenues | $ 97,759 | $540,321 | $209,172 | $272,409 | $130,742 |
| Operating Income | 9,456 | 79,968 | 24,502 | 33,296 | 16,938 |
| Income Before Extraordinary Items | 2,449 | 58,233 | 14,700 | 18,786 | 8,070 |
| Net Income | 2,449 | 58,233 | 14,700 | 18,786 | 8,070 |
| **September 30** | | | | | |
| Operating Revenues | $106,698 | $582,702 | $358,710 | $377,442 | $201,191 |
| Operating Income | 13,790 | 96,652 | 56,437 | 61,312 | 16,565 |
| Income Before Extraordinary Items | 6,761 | 77,061 | 54,329 | 47,537 | 10,670 |
| Net Income | 6,761 | 58,185 | 54,329 | 47,537 | 10,670 |
| **December 31** | | | | | |
| Operating Revenues | $108,742 | $559,468 | $233,398 | $262,203 | $144,326 |
| Operating Income | 10,935 | (14,906) | 4,870 | 10,939 | 9,057 |
| Income (Loss) Before Extraordinary Items | 3,501 | (78,897) | (3,531) | (1,314) | 4,877 |
| Net Income (Loss) | 3,501 | (78,897) | (3,531) | (1,314) | 4,877 |

In the fourth quarter of 2000 earnings for APCo, CSPCo, I&M, and OPCo were effected by a ruling disallowing interest deductions claimed by AEP relating to its COLI program. The unfavorable amounts are $82 million for APCo, $41 million for CSPCo, $66 million for I&M, $8 million for KPCo and $118 million for OPCo. Additionally I&M incurred costs in the fourth quarter of 2000 for the Cook Plant restart of $35 million.

| Quarterly Periods Ended | AEGCo | APCo | CPL | CSPCo | I&M |
|---|---|---|---|---|---|
| | | | (in thousands) | | |
| 1999 | | | | | |
| March 31 | | | | | |
| Operating Revenues | $52,827 | $427,702 | $282,278 | $279,067 | $334,113 |
| Operating Income | 2,360 | 71,607 | 46,091 | 46,047 | 38,838 |
| Income Before Extraordinary Items | 2,614 | 39,261 | 17,020 | 27,418 | 20,070 |
| Net Income | 2,614 | 39,261 | 17,020 | 27,418 | 20,070 |
| June 30 | | | | | |
| Operating Revenues | $51,612 | $373,766 | $383,783 | $301,419 | $336,553 |
| Operating Income | 1,002 | 43,099 | 79,679 | 54,473 | 26,966 |
| Income Before Extraordinary Items | 1,222 | 11,036 | 51,024 | 34,559 | 9,745 |
| Net Income | 1,222 | 11,036 | 51,024 | 34,559 | 9,745 |
| September 30 | | | | | |
| Operating Revenues | $57,235 | $441,435 | $495,653 | $368,946 | $411,248 |
| Operating Income | 921 | 66,309 | 127,499 | 83,478 | 26,085 |
| Income Before Extraordinary Items | 958 | 35,661 | 103,989 | 63,719 | 8,084 |
| Net Income | 958 | 35,661 | 103,989 | 63,719 | 8,084 |
| December 31 | | | | | |
| Operating Revenues | $55,515 | $408,034 | $320,761 | $280,562 | $312,205 |
| Operating Income | 1,057 | 60,221 | 40,716 | 38,792 | 16,763 |
| Income (Loss) Before Extraordinary Items | 1,401 | 34,534 | 15,685 | 24,574 | (5,123) |
| Net Income (Loss) | 1,401 | 34,534 | 10,168 | 24,574 | (5,123) |

| Quarterly Periods Ended | KPCo | OPCo | PSO | SWEPCo | WTU |
|---|---|---|---|---|---|
| | | | (in thousands) | | |
| 1999 | | | | | |
| March 31 | | | | | |
| Operating Revenues | $ 90,741 | $518,221 | $151,030 | $197,064 | $ 81,052 |
| Operating Income | 15,360 | 78,956 | 12,031 | 25,810 | 6,922 |
| Income Before Extraordinary Items | 8,209 | 60,821 | 2,423 | 12,095 | 932 |
| Net Income | 8,209 | 60,821 | 2,423 | 12,095 | 932 |
| June 30 | | | | | |
| Operating Revenues | $ 86,231 | $498,587 | $178,699 | $242,888 | $107,782 |
| Operating Income | 10,233 | 73,328 | 23,172 | 35,269 | 16,361 |
| Income Before Extraordinary Items | 2,995 | 51,865 | 13,955 | 21,411 | 10,116 |
| Net Income | 2,995 | 51,865 | 13,955 | 21,411 | 10,116 |
| September 30 | | | | | |
| Operating Revenues | $ 94,939 | $544,451 | $258,656 | $312,035 | $164,104 |
| Operating Income | 14,244 | 72,858 | 57,720 | 61,541 | 27,030 |
| Income Before Extraordinary Items | 7,197 | 56,233 | 50,257 | 44,908 | 21,413 |
| Net Income | 7,197 | 56,233 | 50,257 | 41,897 | 15,952 |
| December 31 | | | | | |
| Operating Revenues | $102,071 | $478,004 | $161,005 | $219,540 | $ 92,771 |
| Operating Income | 14,838 | 63,687 | 5,790 | 24,442 | 3,486 |
| Income (Loss) Before Extraordinary Items | 7,029 | 43,238 | (5,127) | 7,791 | (594) |
| Net Income (Loss) | 7,029 | 43,238 | (5,127) | 7,791 | (594) |

## 21. Trust Preferred Securities:

The following Trust Preferred Securities issued by the wholly-owned statutory business trusts of CPL, PSO and SWEPCo were outstanding at December 31, 2000 and December 31, 1999. They are classified on the balance sheets as certain subsidiaries Obligated, Mandatorily Redeemable Preferred Securities of Subsidiary Trusts Holding Solely Junior Subordinated Debentures of such subsidiaries. The Junior Subordinated Debentures mature on April 30, 2037. CPL reacquired 60,000 trust preferred units during 2000.

| Business Trust | Security | Units issued/ outstanding at 12/31/00 | 2000 Amount (millions) | 1999 Amount (millions) | Description of Underlying Debentures of Registrant |
|---|---|---|---|---|---|
| CPL Capital I | 8.00%, Series A | 5,940,000 | $149 | $150 | CPL, $153 million, 8.00%, Series A |
| PSO Capital I | 8.00%, Series A | 3,000,000 | 75 | 75 | PSO, $77 million, 8.00%, Series A |
| SWEPCo Capital I | 7.875%, Series A | 4,400,000 | 110 | 110 | SWEPCo, $113 million, 7.875%, Series A |
| | | 13,340,000 | $334 | $335 | |

Each of the business trusts is treated as a subsidiary of its parent company. The only assets of the business trusts are the subordinated debentures issued by their parent company as specified above. In addition to the obligations under their subordinated debentures, each of the parent companies has also agreed to a security obligation which represents a full and unconditional guarantee of its capital trust obligation.

## 22. Jointly Owned Electric Utility Plant:

CPL, CSP, PSO, SWEPCo and WTU have generating units that are jointly owned with unaffiliated companies. Each of the participating companies is obligated to pay its share of the costs of any such jointly owned facilities in the same proportion as its ownership interest. Each AEP registrant subsidiary's proportionate share of the operating costs associated with such facilities is included in its statements of income and the investments are reflected in its balance sheets under utility plant as follows:

| | | Company's Share December 31, | | | |
|---|---|---|---|---|---|
| | | 2000 | | 1999 | |
| | Percent of Ownership | Utility Plant in Service | Construction Work in Progress | Utility Plant in Service | Construction Work in Progress |
| | | (in thousands) | | (in thousands) | |
| **CPL:** | | | | | |
| Oklaunion Generating Station (Unit No. 1) | 7.8 | $ 37,236 | $ 395 | $ 37,236 | $ - |
| South Texas Project Generating Station (Units No. 1 and 2) | 25.2 | 2,373,575 | 19,292 | 2,351,795 | 56,021 |
| | | $2,410,811 | $19,687 | $2,389,031 | $56,021 |
| **CSP:** | | | | | |
| W.C. Beckjord Generating Station (Unit No. 6) | 12.5 | $ 14,108 | $ 178 | $ 13,919 | $ 390 |
| Conesville Generating Station (Unit No. 4) | 43.5 | 80,103 | 261 | 80,433 | 80 |
| J.M. Stuart Generating Station | 26.0 | 191,875 | 10,086 | 184,168 | 3,620 |
| Wm. H. Zimmer Generating Station | 25.4 | 706,549 | 5,265 | 701,054 | 6,030 |
| Transmission | (a) | 61,820 | 451 | 60,333 | 1,210 |
| | | $1,054,455 | $16,241 | $1,039,907 | $11,330 |
| **PSO:** | | | | | |
| Oklaunion Generating Station (Unit No. 1) | 15.6 | $ 81,185 | $ 817 | $ 81,185 | $ - |
| **SWEPCo:** | | | | | |
| Dolet Hills Generating Station (Unit No. 1) | 40.2 | $ 231,442 | $ 1,984 | $ 230,971 | $ 1,771 |
| Flint Creek Generating Station (Unit No. 1) | 50.0 | 82,899 | 852 | 81,895 | 286 |
| Pirkey Generating Station (Unit No. 1) | 85.9 | 437,069 | 435 | 434,960 | 1,777 |
| | | $ 751,410 | $ 3,271 | $ 747,826 | $ 3,834 |
| **WTU:** | | | | | |
| Oklaunion Generating Station (Unit No. 1) | 54.7 | $ 277,624 | $ 3,295 | $ 281,777 | $ - |

(a) Varying percentages of ownership.

The accumulated depreciation with respect to each AEP registrant subsidiary's share of jointly owned facilities is shown below:

| | December 31, 2000 | 1999 |
|---|---|---|
| | (in thousands) | |
| CPL | $834,722 | $758,460 |
| CSPCo | 389,558 | 361,113 |
| PSO | 33,669 | 36,374 |
| SWEPCo | 367,558 | 354,360 |
| WTU | 98,045 | 93,807 |

## 23. Related Party Transactions

*AEP System Power Pool*

APCo, CSPCo, I&M, KEPCo and OPCo are parties to the Interconnection Agreement, dated July 6, 1951, as amended (the Interconnection Agreement), defining how they share the costs and benefits associated with their generating plants. This sharing is based upon each company's "member-load-ratio," which is calculated monthly on the basis of each company's maximum peak demand in relation to the sum of the maximum peak demands of all five companies during the preceding 12 months. In addition, since 1995, APCo, CSPCo, I&M, KEPCo and OPCo have been parties to the AEP System Interim Allowance Agreement which provides, among other things, for the transfer of SO2 Allowances associated with transactions under the Interconnection Agreement.

Power marketing and trading transactions (trading activities) are conducted by the AEP Power Pool and shared among the parties under the Interconnection Agreement.

In addition, the AEP Power Pool enters into transactions for the purchase and sale of electricity options, futures and swaps, and for the forward purchase and sale of electricity outside of the AEP System's traditional marketing area.

CPL, PSO, SWEPCo, WTU and AEP Service Corporation are parties to a Restated and Amended Operating Agreement originally dated as of January 1, 1997 (CSW Operating Agreement). The CSW Operating Agreement requires the operating companies of the west zone to maintain specified annual planning reserve margins and requires the subsidiaries that have capacity in excess of the required margins to make such capacity available for sale to other AEP subsidiaries as capacity commitments. The CSW Operating Agreement also delegates to AEP Service Corporation the authority to coordinate the acquisition, disposition, planning, design and construction of generating units and to supervise the operation and maintenance of a central control center. The CSW Operating Agreement has been accepted for filing and allowed to become effective by FERC.

AEP's System Integration Agreement provides for the integration and coordination of AEP's east and west zone operating subsidiaries, joint dispatch of generation within the AEP System, and the distribution, between the two operating zones, of costs and benefits associated with the System's generating plants. It is designed to function as an umbrella agreement in addition to the AEP Interconnection Agreement and the CSW Operating Agreement, each of which will continue to control the distribution of costs and benefits within each zone.

The following table shows the revenues derived from sales to the Pools and direct sales to affiliates for years ended December 31, 2000, 1999 and 1998:

| Related Party Revenues | | APCo | CSPCo | I&M | KPCo | OPCo | AEGCo |
|---|---|---|---|---|---|---|---|
| | | | | (in thousands) | | | |
| 2000 | Sales to East System Pool | $ 81,013 | $36,884 | $200,474 | $36,554 | $502,140 | $ - |
| | Sales to West System Pool | 7,697 | 4,095 | 4,614 | 1,829 | 6,356 | - |
| | Direct Sales To East Affiliates | 59,106 | - | - | - | 66,487 | 227,983 |
| | Direct Sales To West Affiliates | 4,092 | 2,262 | 2,510 | 972 | 3,421 | - |
| | Total Revenues | $151,908 | $43,241 | $207,598 | $39,355 | $578,404 | $227,983 |
| 1999 | Sales to East System Pool | $41,869 | $15,136 | $50,624 | $43,157 | $337,699 | $ - |
| | Direct Sales To East Affiliates | 57,201 | - | - | - | 50,968 | 152,559 |
| | Total Revenues | $99,070 | $15,136 | $50,624 | $43,157 | $388,667 | $152,559 |
| 1998 | Sales to East System Pool | $36,930 | $20,128 | $37,561 | $43,543 | $363,343 | $ - |
| | Direct Sales To East Affiliates | 56,753 | - | - | - | 55,167 | 153,537 |
| | Total Revenues | $93,683 | $20,128 | $37,561 | $43,543 | $418,510 | $153,537 |

| Related Party Revenues | | CPL | PSO | SWEPCo | WTU |
|---|---|---|---|---|---|
| | | (in thousands) | | | |
| 2000 | Sales to East System Pool | $ - | $ - | $ - | $ - |
| | Sales to West System Pool | 23,421 | 7,323 | 5,546 | 194 |
| | Direct Sales To East Affiliates | (3,348) | (1,990) | (3,008) | (1,116) |
| | Direct Sales To West Affiliates | 12,516 | 21,995 | 62,178 | 7,645 |
| | Total Revenues | $32,589 | $27,328 | $64,716 | $ 6,723 |
| 1999 | Sales to West System Pool | $ 6,124 | $ 3,097 | $ 4,527 | $ 401 |
| | Direct Sales To West Affiliates | 7,470 | 7,968 | 49,542 | 2,576 |
| | Total Revenues | $13,594 | $11,065 | $54,069 | $2,977 |
| 1998 | Sales to West System Pool | $ 7,853 | $ 3,223 | $ 5,660 | $ 270 |
| | Direct Sales To West Affiliates | 9,798 | 10,196 | 29,811 | 2,190 |
| | Total Revenues | $17,651 | $13,419 | $35,471 | $2,460 |

The following table shows the purchased power expense incurred from purchases from the Pools and affiliates for the years ended December 31, 2000, 1999, and 1998:

| Related Party Purchases | | APCo | CSPCo | I&M | KPCo | OPCo |
|---|---|---|---|---|---|---|
| | | (in thousands) | | | | |
| 2000 | Purchases from East System Pool | $355,305 | $287,482 | $106,644 | $ 58,150 | $50,339 |
| | Purchases from West System Pool | 455 | 260 | 285 | 108 | 390 |
| | Direct Purchases from East Affiliates | - | - | 158,537 | 69,446 | - |
| | Direct Purchases from West Affiliates | 14 | 8 | 9 | 3 | 12 |
| | Total Purchases | $355,774 | $287,750 | $265,475 | $127,707 | $50,741 |
| 1999 | Purchases from East System Pool | $130,991 | $199,574 | $112,350 | $19,502 | $ 20,864 |
| | Direct Purchases from East Affiliates | - | - | 88,022 | 64,498 | - |
| | Total Purchases | $130,991 | $199,574 | $200,372 | $84,000 | $ 20,864 |
| 1998 | Purchases from East System Pool | $180,762 | $167,619 | $125,240 | $ 9,673 | $ 18,211 |
| | Direct Purchases from East Affiliates | - | - | 86,246 | 67,291 | - |
| | Total Purchases | $180,762 | $167,619 | $211,486 | $76,964 | $ 18,211 |

| Related Party Purchases | | CPL | PSO | SWEPCo | WTU |
|---|---|---|---|---|---|
| | | (in thousands) | | | |
| 2000 | Purchases from East System Pool | $ - | $20,100 | $ - | $ - |
| | Purchases from West System Pool | 1,696 | 5,386 | 4,379 | 18,444 |
| | Direct Purchases from East Affiliates | 251 | 2,117 | - | 71 |
| | Direct Purchases from West Affiliates | 30,644 | 33,185 | 8,264 | 39,258 |
| | Total Purchases | $32,591 | $60,788 | $12,643 | $57,773 |
| 1999 | Purchases from West System Pool | $ 895 | $ 6,992 | $1,295 | $ 7,266 |
| | Direct Purchases from West Affiliates | 15,778 | 27,627 | 6,256 | 19,325 |
| | Total Purchases | $16,673 | $34,619 | $7,551 | $26,591 |
| 1998 | Purchases from West System Pool | $1,091 | $ 5,022 | $ 2,579 | $ 8,314 |
| | Direct Purchases from West Affiliates | 8,636 | 15,970 | 7,576 | 20,935 |
| | Total Purchases | $9,727 | $20,992 | $10,155 | $29,249 |

*AEP System Transmission Pool*

APCo, CSPCo, I&M, KEPCo and OPCo are parties to the Transmission Agreement, dated April 1, 1984, as amended (the Transmission Agreement), defining how they share the costs associated with their relative ownership of the extra-high-voltage transmission system (facilities rated 345 kw and above) and certain facilities operated at lower voltages (138 kv and above). Like the Interconnection Agreement, this sharing is based upon each company's "member-load-ratio."

The following table shows the net (credits) or charges allocated among the parties to the Transmission Agreement during the years ended December 31, 1998, 1999 and 2000:

| | 1998 | 1999 (in thousands) | 2000 |
|---|---|---|---|
| APCo | $ (2,400) | $ (8,300) | $ (3,400) |
| CSPCo | 35,600 | 39,000 | 38,300 |
| I&M | (44,100) | (43,900) | (43,800) |
| KEPCo | (6,000) | (4,300) | (6,000) |
| OPCo | 16,900 | 17,500 | 14,900 |

CPL, PSO, SWEPCo, WTU and AEP Service Corporation are parties to a Transmission Coordination Agreement originally dated as of January 1, 1997 (TCA). The TCA established a coordinating committee, which is charged with the responsibility of overseeing the coordinated planning of the transmission facilities of the west zone operating subsidiaries, including the performance of transmission planning studies, the interaction of such subsidiaries with independent system operators (ISO) and other regional bodies interested in transmission planning and compliance with the terms of the Open Access Transmission Tariff (OATT) filed with the FERC and the rules of the FERC relating to such tariff.

Under the TCA, the west zone operating subsidiaries have delegated to AEP Service Corporation the responsibility of monitoring the reliability of their transmission systems and administering the OATT on their behalf. The TCA also provides for the allocation among the west zone operating subsidiaries of revenues collected for transmission and ancillary services provided under the OATT. In December 1999, the FERC approved the TCA filing based on the revised revenue allocation ratios effective as of January 1, 1997. In January 2000, the west zone operating companies settled among themselves, including interest, under the revised TCA.

The following table shows the net (credits) or charges, excluding interest, allocated among the west zone operating companies during the years ended December 31, 1998, 1999 and 2000:

| | 1998 | 1999 (in thousands) | 2000 |
|---|---|---|---|
| CPL | $ - | $ - | $(15,498) |
| WTU | 1,139 | (28) | (23,443) |
| SWEPCo | 3,572 | 1,058 | 22,115 |
| PSO | (4,711) | (1,030) | 16,826 |

AEP's System Transmission Integration Agreement provides for the integration and coordination of the planning, operation and maintenance of the transmission facilities of AEP's east and west zone operating subsidiaries. Like the System Integration Agreement, the System Transmission Integration Agreement functions as an umbrella agreement in addition to the AEP Transmission Agreement and the Transmission Coordination Agreement. The System Transmission Integration Agreement contains two service schedules that govern:

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

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

*Unit Power Agreements and Other*

A unit power agreement between AEGCo and I&M (the I&M Power Agreement) provides for the sale by AEGCo to I&M of all the power (and the energy associated therewith) available to AEGCo at the Rockport Plant. I&M is obligated, whether or not power is available from AEGCo, to pay as a demand charge for the right to receive such power (and as an energy charge for any associated energy taken by I&M) such amounts, as when added to amounts received by AEGCo from any other sources, will be at least sufficient to enable AEGCo to pay all its operating and other expenses, including a rate of return on the common equity of AEGCo as approved by FERC, currently 12.16%. The I&M Power Agreement will continue in effect until the expiration of the lease term of Unit 2 of the Rockport Plant unless extended in specified circumstances.

Pursuant to an assignment between I&M and KEPCo, and a unit power agreement between KEPCo and AEGCo, AEGCo sells KEPCo 30% of the power (and the energy associated therewith) available to AEGCo from both units of the Rockport Plant. KEPCo has agreed to pay to AEGCo in consideration for the right to receive such power the same amounts which I&M would have paid AEGCo under the terms of the I&M Power Agreement for such entitlement. The KEPCo unit power agreement expires on December 31, 2004.

APCo and OPCo, jointly own two power plants. The costs of operating these facilities are apportioned between the owners based on ownership interests. Each company's share of these costs is included in the appropriate expense accounts on each company's consolidated statements of income. Each company's investment in these plants is included in electric utility plant on its consolidated balance sheets.

I&M provides barging services to AEGCo, APCo and OPCo. I&M records revenues from barging services as nonoperating income. AEGCo, APCo and OPCo record costs paid to I&M for barging services as fuel expense. The amount of affiliated revenues and affiliated expenses were:

| Company | Year Ended December 31, 2000 | 1999 | 1998 |
|---|---|---|---|
| | (in millions) | | |
| I&M - revenues | $23.5 | $28.1 | $24.8 |
| AEGCo - expense | 8.8 | 8.5 | 8.8 |
| APCo - expense | 7.8 | 10.5 | 8.5 |
| OPCo - expense | 6.9 | 9.1 | 7.5 |

American Electric Power Service Corporation (AEPSC) provides certain managerial and professional services to AEP System companies. The costs of the services are billed to its affiliated companies by AEPSC on a direct-charge basis, whenever possible, and on reasonable bases of proration for shared services. The billings for services are made at cost and include no compensation for the use of equity capital, which is furnished to AEPSC by AEP Co., Inc. Billings from AEPSC are capitalized or expensed depending on the nature of the services rendered. AEPSC and its billings are subject to the regulation of the SEC under the 1935 Act.

The following is a combined presentation of management's discussion and analysis of financial condition, contingencies and other matters for AEP and certain of its registrant subsidiaries. Management's discussion and analysis of results of operations for AEP and each of its subsidiary registrants is presented with their financial statements earlier in this document. The following is a list of sections of management's discussion and analysis of financial condition, contingencies and other matters and the registrant to which they apply:

| | |
|---|---|
| Financial Condition | AEP, APCo, CPL, I&M, OPCo, SWEPCo |
| Market Risks | AEP, AEGCo, APCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, WTU |
| Industry Restructuring | AEP, APCo, CPL, CSPCo, I&M, OPCo, PSO, SWEPCo, WTU |
| Litigation | AEP, APCo, CPL, CSPCo, I&M, KPCo, OPCo, SWEPCo, WTU |
| Environmental Concerns and Issues | AEP, APCo, CPL, CSPCo, I&M, OPCo, SWEPCo |
| Foreign Energy Delivery, Worldwide Energy Investments and Other Business Operations | AEP |
| Other Matters | AEP, AEGCo, APCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, WTU |

## Financial Condition – Affecting AEP, APCo, CPL, I&M, OPCo and SWEPCo

The Cook Plant extended outage and related restart expenditures negatively affected AEP's 2000 earnings and cash flows and the write-off related to COLI and non-regulated subsidiaries further depressed earnings. Although the 2000 dividend payout ratio was 289%, it is expected that the ratio will improve significantly as a result of earnings growth in 2001. It has been a management objective to reduce the payout ratio by increasing earnings. Management expects to grow future earnings by growing the wholesale business and by controlling operations and maintenance costs.

AEP's common equity to total capitalization, including long-term debt due within one year and short-term debt, decreased from 37% in 1999 to 34% in 2000. Preferred stock at 1% remained unchanged. Long-term debt decreased from 50% to 47%, while short-term debt increased from 12% to 18%. AEP's intention is to maintain flexibility during corporate separation by issuing floating rate debt. In 2000, AEP did not issue any shares of common stock to meet the requirements of the Dividend Reinvestment and Direct Stock Purchase Plan and the Employee Savings Plan. Sales of common stock and/or equity linked securities may be necessary in the future to support AEP's plan to grow the business.

Expenditures by the AEP System for domestic electric utility construction are estimated to be $6 billion for the next three years. Approximately 70% of those construction expenditures are expected to be financed by internally generated funds.

Construction expenditures for the registrant subsidiaries for the next three years excluding AFUDC are:

| | Projected Construction Expenditures (in millions) | Construction Expenditures Financed with Internal Funds |
|---|---|---|
| APCo | $1,122.8 | 79% |
| I&M | 427.2 | ALL |
| OPCo | 1,044.5 | ALL |
| CPL | 745.1 | NONE |
| SWEPCo | 405.6 | 70% |

The year-end ratings of the subsidiaries' first mortgage bonds are listed in the following table:

| Company | Moody's | S&P | Fitch |
|---|---|---|---|
| APCo | A3 | A | A- |
| CSPCo | A3 | A- | A |
| I&M | Baa1 | A- | BBB+ |
| KPCo | Baa1 | A- | BBB+ |
| OPCo | A3 | A- | A- |
| CPL | A3 | A- | A |
| PSO | A1 | A | A+ |
| SWEPCo | A1 | A | A+ |
| WTU | A2 | A- | A |

The ratings at the end of the year for senior unsecured debt issued by the subsidiaries are listed in the following table:

| Company | Moody's | S&P | Fitch |
|---|---|---|---|
| AEP Resources* | Baa2 | BBB+ | BBB+ |
| APCo | Baa1 | BBB+ | BBB+ |
| CSPCo | Baa1 | BBB+ | A- |
| I&M | Baa2 | BBB+ | BBB |
| KPCo | Baa2 | BBB+ | BBB |
| OPCo | Baa1 | BBB+ | BBB+ |
| CPL | Baa1 | BBB+ | A- |
| PSO | A2 | BBB+ | A |
| SWEPCo | A2 | BBB+ | A |
| WTU | A3 | BBB+ | - |

- The rating is for a series of senior notes issued with a Support Agreement from AEP.

*Financing Activity*

Debt was issued in 2000 for the funding of debt maturities, for construction programs and for the growth of the wholesale business. AEP and its subsidiaries issued $1.1 billion principal amount of long-term obligations in 2000 at variable interest rates with due dates ranging from 2001 to 2007. The principal amount of long-term debt retirements, including maturities, totaled $1.6 billion with interest rates ranging from 5.25% to 9.6%.

The principal amount of long-term obligations issued and retired in 2000 by the registrant subsidiaries was:

| | Issuance | Retirements |
|---|---|---|
| | (in thousands) | |
| APCo | $ 75,000 | $136,000 |
| I&M | 200,000 | 148,000 |
| OPCo | 75,000 | 32,102 |
| CPL | 150,000 | 150,000 |
| SWEPCo | 150,000 | 45,595 |

The domestic electric utility subsidiaries generally issue short-term debt to provide for interim financing of capital expenditures that exceed internally generated funds. They periodically reduce their outstanding short-term debt through issuances of long-term debt and additional capital contributions by the parent company. The sources of funds available to the parent company, AEP, are dividends from its subsidiaries, short-term and long-term borrowings and proceeds from the issuance of common stock.

The subsidiaries formed to pursue worldwide electric and gas opportunities use short-term debt and capital contributions from the parent company for interim financing of working capital and acquisitions. Short-term debt is replaced with long-term debt when financial market conditions are favorable. Some acquisitions of existing business entities include the assumption of their outstanding debt.

The AEP System uses short-term debt, primarily commercial paper, to meet fluctuations in working capital requirements and other interim capital needs. AEP has established a system money pool to meet the short-term borrowings for certain of its subsidiaries, including AEGCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo and WTU. In January 2001 APCo became a participant in AEP's money pool and retired all outstanding short-term debt. In addition, AEP also funds the short-term debt requirements of other subsidiaries that are not included in the money pool. As of December 31, 2000, AEP had back up credit facilities totaling $3.5 billion to support its commercial paper program. At December 31, 2000, AEP had $2.7 billion outstanding in short-term borrowings. The maximum amount of short-term borrowings outstanding during the year, which had a weighted average interest rate for the year of 7.5%, was $2.7 billion during December 2000.

AEP Credit purchases, without recourse, the accounts receivable of most of the domestic utility operating companies and certain non-affiliated electric utility companies. The sale of accounts receivable provides the domestic electric utility operating companies with cash immediately, thereby reducing working capital needs and revenue requirements. In addition, AEP Credit's capital structure contains greater leverage than that of the domestic electric utility operating companies, so cost of capital is lowered. AEP Credit issues commercial paper to meet its financing needs. At December 31, 2000, AEP Credit had a $2.0 billion unsecured back up credit facility to support its commercial paper program, which had $1.2 billion outstanding. The maximum amount of such commercial paper outstanding during the year, which had a weighted average interest rate of 6.6%, was $1.5 billion during September 2000.

**Market Risks – Affecting AEP, AEGCo, APCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo and WTU**

AEP as a major power producer and a trader of wholesale electricity and natural gas has certain market risks inherent in its business activities. The trading of electricity and natural gas and related financial derivative instruments exposes AEP to market risk. Market risk represents the risk of loss that may impact due to changes in commodity market prices and rates. Policies and procedures have been established to identify, assess, and manage market risk exposures including the use of a risk measurement model which calculates Value at Risk (VaR). The VaR is based on the variance - covariance method using historical prices to estimate volatilities and correlations and assuming a 95% confidence level and a one-day holding period. Throughout the year ending December 31, 2000 the average, high, and low VaRs in the wholesale electricity and gas trading portfolio were $10 million, $32 million, and $1 million, respectively. The average, high, and low VaRs for the year ending December 31, 1999 were $4 million, $8 million, and $1 million, respectively. Based on this VaR analysis, at December 31, 2000 a near term typical change in commodity prices is not expected to have a material effect on AEP's results of operations, cash flows or financial condition. The following table shows the high and average U.S. electricity market risk as measured by VaR allocated to the AEP registrant subsidiaries based upon the AEP System's trading activities in the U.S. Low VaR is excluded because all companies are under $1 million.

VaR for Registrant Subsidiaries:

| | December 31, | | | |
|---|---|---|---|---|
| | 2000 | | 1999 | |
| | High | Average | High | Average |
| | (in millions) | | | |
| APCo | $2 | $6 | $1 | $2 |
| CPL | 1 | 4 | - | - |
| CSPCo | 1 | 3 | 1 | 1 |
| I&M | 1 | 4 | 1 | 2 |
| KPCo | - | 1 | - | 1 |
| OPCo | 2 | 5 | 1 | 2 |
| PSO | 1 | 3 | - | - |
| SWEPCo | 1 | 4 | - | - |
| WTU | - | 1 | - | - |

Investments in foreign ventures expose AEP to risk of foreign currency fluctuations. AEP's exposure to changes in foreign currency exchange rates related to these foreign ventures and investments is not expected to be significant for the foreseeable future.

AEP is exposed to changes in interest rates primarily due to short-and long-term borrowings to fund its business operations. AEP measures interest rate market risk exposure utilizing a VaR model. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one year holding period. The volatilities and correlations were based on three years of weekly prices. The risk of potential loss in fair value attributable to AEP's exposure to interest rates, primarily related to long-term debt with fixed interest rates, was $998 million at December 31, 2000 and $966 million at December 31, 1999. The following table shows the potential loss in fair value as measured by VaR allocated to the AEP registrant subsidiaries based upon debt outstanding:

VaR for Registrant Subsidiaries:

| Company | December 31, 2000 | 1999 |
|---|---|---|
| | (in millions) | |
| AEGCo | $ 4 | $ 4 |
| APCo | 149 | 144 |
| CPL | 135 | 131 |
| CSPCo | 84 | 81 |
| I&M | 129 | 125 |
| KPCo | 31 | 30 |
| OPCo | 112 | 109 |
| PSO | 44 | 42 |
| SWEPCo | 60 | 58 |
| WTU | 24 | 23 |

AEP and its registrant subsidiaries would not expect to liquidate its entire debt portfolio in a one year holding period. Therefore, a near term change in interest rates should not materially affect results of operations or the consolidated financial position of AEP and its registrant subsidiaries. AEP is currently utilizing interest rate swaps as a hedge to manage its exposure to interest rate fluctuations in the U.K. and Australia.

AEP has investments in debt and equity securities which are held in nuclear trust funds. The trust investments and their fair value are discussed in Note 15 of the Notes to Consolidated Financial Statements. Instruments in the trust funds have not been included in the market risk calculation for interest rates as these instruments are marked-to-market and changes in market value are reflected in a corresponding decommissioning liability. Any differences between the trust fund assets and the ultimate liability should be recoverable from ratepayers.

AEGCo is not exposed to risk from changes in interest rates on short-term and long-term borrowings used to finance operations since financing costs are recovered through the unit power agreements.

Inflation affects the AEP's System's cost of replacing utility plant and the cost of operating and maintaining its plant. The rate-making process limits recovery to the historical cost of assets, resulting in economic losses when the effects of inflation are not recovered from customers on a timely basis. However, economic gains that result from the repayment of long-term debt with inflated dollars partly offset such losses.

## Industry Restructuring

In 2000 California's deregulated energy market suffered problems including high energy prices, short energy supply, and financial difficulties for retail energy suppliers whose prices to customers are controlled. This energy crisis has highlighted the importance of risk management and has contributed to certain state regulatory and legislative actions which could delay the start of customer choice and the transition to competitive, market based pricing for retail electricity supply in some of the states in which the AEP System companies operate. Seven of the eleven state retail jurisdictions in which the domestic electric utility companies operate have enacted restructuring legislation. In general, the legislation provides for a transition from cost-based regulation of bundled electric service to customer choice and market pricing for the supply of electricity. As legislative and regulatory proceedings evolve, six of the electric operating companies (APCo, CPL, CSPCo, OPCo, SWEPCo and WTU) doing business in five of the seven states that have passed restructuring legislation have discontinued the application of SFAS 71 regulatory accounting for generation. The seven states in various stages of restructuring to transition generation to market based pricing are Arkansas, Michigan, Ohio, Oklahoma, Texas, Virginia, and West Virginia. PSO and I&M have not discontinued regulatory accounting for their generation business in Oklahoma and Michigan, respectively, pending the implementation of the legislation. The following is a summary of restructuring legislation, the status of the transition plans and the status of the electric utility companies' accounting to comply with the changes in each of the AEP System's seven state regulatory jurisdictions affected by restructuring legislation.

*Ohio Restructuring – Affecting AEP, CSPCo and OPCo*

Effective January 1, 2001, customer choice of electricity supplier began under the Ohio Act. In February 2001, one supplier announced its plan to offer service to

CSPCo's residential customers. Currently for residential customers of OPCo, no alternative suppliers have registered with the PUCO as required by the Ohio Act. Two alternative suppliers have been approved to compete for CSPCo's and OPCo's commercial and industrial customers. Presently, customers continue to be served by CSPCo and OPCo with a legislatively required residential rate reduction of 5% for the generation portion of rates and a freezing of generation rates including fuel rates starting on January 1, 2001.

The Ohio Act provides for a five-year transition period to move from cost based rates to market pricing for generation services. It granted the PUCO broad oversight responsibility for promulgation of rules for competitive retail electric generation service, approval of a transition plan for each electric utility company and addressing certain major transition issues including unbundling of rates and the recovery of stranded costs including regulatory assets and transition costs.

The Ohio Act also provides for a reduction in property tax assessments, the imposition of replacement franchise and income taxes, and the replacement of a gross receipts tax with a KWH based excise tax. The property tax assessment percentage on generation property was lowered from 100% to 25% of value effective January 1, 2001 and Ohio electric utilities will become subject to the Ohio Corporate Franchise Tax and municipal income taxes on January 1, 2002. The last year for which Ohio electric utilities will pay the excise tax based on gross receipts is the tax year ending April 30, 2002. As of May 1, 2001 electric distribution companies will be subject to an excise tax based on KWH sold to Ohio customers. The gross receipts tax is paid at the beginning of the tax year (May 1), deferred by CSPCo and OPCo as a prepaid expense and amortized to expense during the tax year pursuant to the tax law whereby the payment of the tax results in the privilege to conduct business in the year following the payment of the tax. As a result a duplicate tax will be expensed from May 1, 2001 through April 30, 2002 adding approximately $90 million to AEP consolidated tax expense ($40 million for CSPCo and $50 million for OPCo) during that period. Unless the companies can recover the duplicate amount from ratepayers it will negatively impact results of operations.

On September 28, 2000, the PUCO approved, with minor modifications, a stipulation agreement between CSPCo, OPCo, the PUCO staff, the Ohio Consumers' Counsel and other concerned parties regarding transition plans filed by CSPCo and OPCo. The key provisions of this stipulation agreement are:

- Recovery of generation-related regulatory assets at December 31, 2000 over seven years for OPCo ($518 million) and over eight years for CSPCo ($248 million) through frozen transition rates for the first five years of the recovery period and a wires charge for the remaining years.
- A shopping incentive (a price credit) of 2.5 mills per KWH for the first 25% of CSPCo residential customers that switch suppliers. There is no shopping incentive for OPCo customers.
- The absorption of $40 million by CSPCo and OPCo ($20 million per company) of consumer education, implementation and transition plan filing costs with deferral of the remaining costs, plus a carrying charge, as a regulatory asset for recovery in future distribution rates.
- CSPCo and OPCo will make available a fund of up to $10 million to reimburse customers who choose to purchase their power from another company for certain transmission charges imposed by PJM and/or a Midwest ISO on generation originating in the Midwest ISO or PJM areas.
- The statutory 5% reduction in the generation component of residential tariffs will remain in effect for the entire five year transition period.
- The companies' request for a $90 million ($40 million for CSPCo and $50 million for OPCo) gross receipts tax rider to recover the duplicate gross receipts KWH based excise tax would be considered separately by the PUCO.

The approved stipulation agreement also accepted the following provisions contained in CSPCo's and OPCo's filed transition plans:

- a corporate separation plan to segregate generation, transmission and distribution assets into separate legal entities, and
- a plan for independent operation of transmission facilities.

The gross receipts tax issue was considered by the PUCO in hearings held in June 2000. In the September 28, 2000 order approving the stipulation agreement, the PUCO determined that there was no duplicate tax overlap period and denied the request for a $90 million ($40 million for CSPCo and $50 million for OPCo) gross receipts tax rider. CSPCo's and OPCo's request for rehearing of the gross receipts tax issue was denied. An appeal of this issue to the Ohio Supreme Court has been filed. Unless this issue is resolved in the companies' favor, it will have an adverse effect on future results of operations and financial position.

One of the intervenors at the hearings for approval of the settlement agreement (whose request for rehearing was denied by the PUCO) has filed with the Ohio Supreme Court for review of the settlement agreement including recovery of regulatory assets. Management is unable to predict the outcome of litigation but the resolution of this matter could negatively impact results of operations.

Beginning January 1, 2001, CSPCo's and OPCo's fuel costs will not be subject to PUCO fuel recovery proceedings. Deferred fuel costs at December 31, 2000 which represent under or over recoveries were one of the items included in the PUCO's final determination of net regulatory assets to be collected (recovered) during the transition period. The elimination of fuel clause recoveries in 2001 in Ohio will subject AEP, CSPCo and OPCo to the risk of fuel market price increases and could adversely affect their future results of operations and cash flows.

*CSPCo and OPCo Discontinue Application of SFAS 71 Regulatory Accounting for the Ohio Jurisdiction*

In September 2000 CSPCo and OPCo discontinued the application of SFAS 71 for their Ohio retail jurisdictional generation business since generation is no longer cost-based regulated in the Ohio jurisdiction and management was able to determine their transition rates and wires charges. The discontinuance in the Ohio jurisdiction was possible as a result of the PUCO's September 28, 2000 approval of the stipulation agreement which established rates, wires charges and net regulatory asset recovery procedures during the transition to market rates.

CSPCo's and OPCo's discontinuance of SFAS 71 for generation resulted in after tax extraordinary losses in the third quarter of 2000 of $25 million and $19 million, respectively, due to certain unrecoverable generation-related regulatory assets and transition expenses. Management believes that substantially all of the remaining net regulatory assets related to the Ohio generation business will be recovered under the PUCO's September 28, 2000 order. Therefore, under the provisions of EITF 97-4, CSPCo's and OPCo's generation-related recoverable net regulatory assets were transferred to the transmission and distribution portion of the business and will be amortized as they are recovered through transition rates to customers. CSPCo and OPCo performed an accounting impairment analysis on their generating assets under SFAS 121 as required when discontinuing the application of SFAS 71 and concluded there was no impairment of generation assets.

*Virginia Restructuring – Affecting AEP and APCo*

In Virginia, a restructuring law provides for a transition to choice of electricity supplier for retail customers beginning on January 1, 2002. In February 2001, restructuring revision legislation was approved by the Virginia Legislature which could modify the terms of restructuring. Presently, the transition period is to be completed, subject to a finding by the Virginia SCC that an effective competitive market exists by January 1, 2004 but no later than January 1, 2005.

The restructuring law also provides an opportunity for recovery of just and reasonable net stranded generation costs. The mechanisms in the Virginia law for net stranded cost recovery are: a capping of rates until as late as July 1, 2007, and the application of a wires charge upon customers who depart the incumbent utility in favor of an alternative supplier prior to the termination of the rate cap. The restructuring law provides for the establishment of capped rates prior to January 1, 2001 based either on a request by APCo for a change in rates prior to January 1, 2001 or on the rates in effect at July 1, 1999 if no rate change request is made and the establishment of a wires charge by the fourth quarter of 2001. APCo did not request new rates; therefore, its current rates are the capped rates. In the third quarter of 2000, the Virginia SCC directed APCo to file a cost of service study using 1999 as a test year to review the reasonableness of APCo's capped rates. The cost of service study was filed on January 3, 2001. In the opinion of APCo's Virginia counsel, Virginia's restructuring law does not permit the Virginia SCC to change rates for the transition period except for changes in the fuel factor, changes in state gross receipts taxes, or to address the utility's financial distress. However, if the Virginia SCC were to reduce APCo's capped rates or deny recovery of regulatory assets, it would adversely affect results of operations if such action is ultimately determined to be legal.

The Virginia restructuring law also requires filings to be made that outline the functional separation of generation from transmission and distribution and a rate unbundling plan. On January 3, 2001, APCo filed its corporate separation plan and rate unbundling plan with the Virginia SCC which is based on the most recent rate case test year (1996). See Note 7 of the Notes to Consolidated Financial Statements for a discussion of AEP's corporate separation plan filed with the SEC.

*West Virginia Restructuring – Affecting AEP and APCo*

On January 28, 2000, the WVPSC issued an order approving an electricity restructuring plan for WV. On March 11, 2000, the WV Legislature approved the restructuring plan by joint resolution. The joint resolution provides that the WVPSC cannot implement the plan until the legislature makes necessary tax law changes to preserve the revenues of the state and local governments. The Joint Committee on Government and Finance of the WV Legislature hired a consultant to study and issue a report on the tax changes required to implement electric restructuring. Moreover, the committee also hired a consultant to study and issue a report on the electric restructuring plan in light of events occurring in California. The WV Legislature is not expected to consider these reports until the 2002 Legislative Session since the 2001 Legislative Session ends in April 2001. Since the WV Legislature has not yet passed the required tax law changes, the restructuring plan has not become effective. AEP subsidiaries, APCo and WPCo, provide electric service in WV.

The provisions of the restructuring plan provide for customer choice to begin after all necessary rules are in place (the "starting date"); deregulation of generation assets on the starting date; functional separation of the generation, transmission and distribution businesses on the starting date and their legal corporate separation no later than January 1, 2005; a transition period of up to 13 years, during which the incumbent utility must provide default service for customers who do not change suppliers unless an alternative default supplier is selected through a WVPSC-sponsored bidding process; capped and fixed rates for the 13 year transition period as discussed below; deregulation of metering and billing; a 0.5 mills per KWH wires charge applicable to all retail customers for a 10-year period commencing with the starting date intended to provide for recovery of any stranded cost including net regulatory assets; establishment of a rate stabilization deferred liability balance of $81 million ($76 million by APCo and $5 million by WPCo) by the end of year ten of the transition period to be used as determined by the WVPSC to offset market prices paid in the eleventh, twelfth, and thirteenth year of the transition period by residential and small commercial customers that do not choose an alternative supplier.

Default rates for residential and small commercial customers are capped for four years after the starting date and then increase as specified in the plan for the next six years. In years eleven, twelve and thirteen of the transition period, the power supply rate shall equal the market price of comparable power.

Default rates for industrial and large commercial customers are discounted by 1% for four and a half years, beginning July 1, 2000, and then increased at pre-defined levels for the next three years. After seven years the power supply rate for industrial and large commercial customers will be market based. APCo's Joint Stipulation agreement, discussed in Note 5 of the Notes to Consolidated Financial Statements, which was approved by the WVPSC on June 2, 2000 in connection with a base rate filing, also provides additional mechanisms to recover regulatory assets.

*APCo Discontinues Application of SFAS 71 Regulatory Accounting*

In June 2000 APCo discontinued the application of SFAS 71 for its Virginia and WV retail jurisdictional portions of its generation business since generation is no longer considered to be cost-based regulated in those jurisdictions and management was able to determine APCo's transition rates and wires charges. The discontinuance in the WV jurisdiction was made possible by the June 2, 2000 approval of the Joint Stipulation which established rates, wires charges and regulatory asset recovery procedures for the transition period to market rates which was determined to be probable. APCo was also able to discontinue application of SFAS 71 for the generation portion of its Virginia retail jurisdiction after management decided that APCo would not request capped rates different from its current rates. The existence of effective restructuring legislation in Virginia and the probability that the WV legislation would become effective with the expected probable passage of required enabling tax legislation in 2001 supported management's decision in 2000 to discontinue SFAS 71 regulatory accounting for APCo's electricity generation and supply business.

APCo's discontinuance of SFAS 71 for generation resulted in an after tax extraordinary gain, in the second quarter of 2000, of $9 million. Management believes that it is probable that substantially all net regulatory assets related to the Virginia and WV generation business will be recovered. Therefore, under the provisions of EITF 97-4, APCo's generation-related net regulatory assets were transferred to the distribution portion of the business and are being amortized as they are recovered through charges to regulated distribution customers. As required by SFAS 101 when discontinuing SFAS 71 regulatory accounting, APCo performed an accounting impairment analysis on its generating assets under SFAS 121 and concluded that there was no accounting impairment of generation assets.

The recent energy crisis in California, discussed above, may be having a chilling effect on efforts to enact the required tax change legislation in West Virginia. The WV Legislature could decide not to enact the required tax changes, thereby, effectively continuing cost based rate regulation in West Virginia or it could modify the restructuring plan. Modifications in the restructuring plan could adversely affect future results of operations if they were to occur. Management is carefully monitoring the situation in West Virginia and continues to work with all concerned parties to get approval to successfully transition our generation business in West Virginia. Failure to pass the required enabling tax changes could ultimately require APCo to re-instate regulatory accounting principles under SFAS 71 for its generation operations in West Virginia.

*Arkansas Restructuring – Affecting AEP and SWEPCo*

In 1999 legislation was enacted in Arkansas that will ultimately restructure the electric utility industry. Its major provisions are:

- retail competition begins January 1, 2002 but can be delayed until as late as June 30, 2003 by the Arkansas Commission;
- transmission facilities must be operated by an ISO if owned by a company which also owns generation assets;
- rates will be frozen for one to three years;
- market power issues will be addressed by the Arkansas Commission; and
- an annual progress report to the Arkansas General Assembly on the development of competition in electric markets and its impact on retail customers is required.

In November 2000 the Arkansas Commission filed its annual progress report with the Arkansas General Assembly recommending a delay in the start date of retail competition to a date between October 1, 2003 and October 1, 2005. The report also asks the Arkansas General Assembly to delegate authority to the Arkansas Commission to determine the appropriate retail competition start date within the approved time frame. In February 2001 the Arkansas General Assembly passed legislation that was signed into law by the Governor that changes the date of electric retail competition to October 1, 2003, and provides the Arkansas Commission with the authority to delay that date for up to two years.

*Texas Restructuring – Affecting AEP, CPL, SWEPCo and WTU*

In June 1999 Texas restructuring legislation was signed into law which, among other things:

- gives Texas customers of investor-owned utilities the opportunity to choose their electricity provider beginning January 1, 2002;
- provides for the recovery of regulatory assets and of other stranded costs through securitization and non-bypassable wires charges;
- requires reductions in NOx and sulfur dioxide emissions;
- provides for a rate freeze until January 1, 2002 followed by a 6% rate reduction for residential and small commercial customers and a number of customer protections;
- provides for an earnings test for each of the three years of the rate freeze period (1999 through 2001) which will reduce stranded cost recoveries or if there is no stranded cost provides for a refund or their use to fund certain capital expenditures in the amount of the excess earnings;
- requires each utility to structurally unbundle into a retail electric provider, a power generation company and a transmission and distribution utility;
- provides for certain limits for ownership and control of generating capacity by companies;
- provides for elimination of the fuel clause reconciliation process beginning January 1, 2002; and
- provides for a 2004 true-up proceeding to determine recovery of stranded costs including final fuel recovery balances, net regulatory assets, certain environmental costs, accumulated excess earnings and other issues.

Under the Texas Legislation, delivery of electricity will continue to be the responsibility of the local electric transmission and distribution utility company at regulated prices. Each electric utility was required to submit a plan to structurally unbundle its business activities into a retail electric provider, a power generation company, and a transmission and distribution utility. In May 2000 CPL, SWEPCo and WTU filed a revised business separation plan that the PUCT approved on July 7, 2000 in an interim order. The revised business separation plans provided for CPL and WTU, which operate in Texas only, to establish separate companies and divide their integrated utility operations and assets into a power generation company, a transmission and distribution utility and a retail electric provider. SWEPCo will separate its Texas jurisdictional transmission and distribution assets and operations into a new Texas regulated transmission and distribution subsidiary. In addition, a retail electric provider will be formed by SWEPCo to provide retail electric service to SWEPCo's Texas jurisdictional customers.

Under the Texas Legislation, electric utilities are allowed, with the approval of the PUCT, to recover stranded generation costs including generation-related regulatory assets that may not be recoverable in a future competitive market. The approved stranded costs can be refinanced through securitization, which is a financing structure designed to provide lower financing costs than are available through conventional financings. Lower financing costs are achieved through the issuance of securitization bonds at a lower interest rate to finance 100% of the costs pursuant to a state pledge to ensure recovery of the bond principal and financing costs through a non-bypassable rate surcharge by the regulated transmission and distribution utility over the life of the securitization bonds.

In 1999 CPL filed an application with the PUCT to securitize approximately $1.27 billion of its retail generation-related regulatory assets and approximately $47 million in other qualified restructuring costs. On March 27, 2000, the PUCT issued an order permitting CPL to securitize approximately $764 million of net regulatory assets. The PUCT's order authorized issuance of up to $797 million of securitization bonds including the $764 million for recovery of net generation-related regulatory assets and $33 million for other qualified refinancing costs. The $764 million for recovery of net generation-related regulatory assets reflects the recovery of $949 million of generation-related regulatory assets offset by $185 million of customer benefits associated with accumulated deferred income taxes. CPL had previously proposed in its filing to flow these benefits back to customers over the 14-year term of the securitization bonds. On April 11, 2000, four parties appealed the PUCT's securitization order to the Travis County District Court. In July 2000 the Travis County District Court upheld the PUCT's securitization order. The securitization order is being appealed to the Supreme Court of Texas. One of these appeals challenges CPL's ability to recover securitization charges under the Texas Constitution. CPL will not be able to issue the securitization bonds until these appeals are resolved.

The remaining regulatory assets of $206 million originally included by CPL in its 1999 securitization request were included in a March 2000 filing with the PUCT, requesting recovery of an additional $1.1 billion of stranded costs. The March 2000 filing of $1.1 billion included recovery of approximately $800 million of STP costs included in property, plant and equipment-electric on AEP's Consolidated Balance Sheets and in electric utility plant-production on CPL's Consolidated Balance Sheets. These STP costs had previously been identified as excess cost over market (ECOM) by the PUCT for regulatory purposes and were earning a lower return and were being amortized on an accelerated basis for rate-making purposes in Texas. The March 2000 filing will determine the initial amount of stranded costs in addition to the securitized regulatory assets to be recovered beginning January 1, 2002.

CPL submitted a revised estimate of stranded costs on October 2, 2000 using assumptions developed in generic proceedings by the PUCT and an administrative model developed by the PUCT staff that reduced the amount of the initial stranded cost estimate to $361 million from the $1.1 billion requested by CPL. CPL subsequently agreed to accept adjustments proposed by intervenors that reduced ECOM to approximately $230 million. Hearings on CPL's requested ECOM were held in October 2000. In February 2001 the PUCT issued an interim decision determining an initial amount of CPL ECOM or stranded costs of negative $580 million. The decision indicated that CPL's costs were below market after securitization of regulatory assets. Management does not agree with the critical inputs to this model. Management believes CPL has a positive stranded cost exclusive of securitized regulatory assets. The final amount of CPL's stranded costs including regulatory assets and ECOM will be established by the PUCT in the legislatively required 2004 true-up proceeding. If CPL's total stranded costs determined in the 2004 true-up are less than the amount of securitized regulatory assets, the PUCT can implement an offsetting credit to transmission and distribution rates.

The PUCT ruled that prior to the 2004 true-up proceeding, no adjustments would be made to the amount of regulatory costs authorized by the PUCT to be securitized. However, the PUCT also ruled that excess earnings for the period 1999-2001 should be refunded through transmission and distribution rates to the extent of any over-mitigation of stranded costs represented by negative ECOM. In the event that CPL will be required to refund excess earnings in the future instead of applying them to reduce ECOM or regulatory assets, it will adversely affect future cash flow but not results of operations since excess earnings for 1999 and 2000 were accrued and expensed in 1999 and 2000. The Texas Legislation allows for several alternative methods to be used to value stranded costs in the final 2004 true-up proceeding including the sale or exchange of generation assets, the issuance of power generation company stock to the public or the use of PUCT staff's ECOM model. To the extent that the final 2004 true-up proceeding determines that CPL should recover additional stranded costs, the total amount recoverable can be securitized.

The Texas Legislation provides that each year during the 1999 through 2001 rate freeze period, electric utilities are subject to an earnings test. For electric utilities with stranded costs, such as CPL, any earnings in excess of the most recently approved cost of capital in its last rate case must be applied to reduce stranded costs. Utilities without stranded costs, such as SWEPCo and WTU, must either flow such excess earnings amounts back to customers or make capital expenditures to improve transmission or distribution facilities or to improve air quality. The Texas Legislation requires PUCT approval of the annual earnings test calculation.

The 1999 earnings test reports filed by CPL, SWEPCo and WTU showed excess earnings of $21 million, $1 million and zero, respectively. The PUCT staff issued its report on the excess earnings calculations filed by CPL, SWEPCo and WTU and calculated the excess earnings amounts to be $41 million, $3 million and $11 million for CPL, SWEPCo and WTU, respectively. The Office of Public Utility Counsel also filed exceptions to the companies' earnings reports. Several issues were resolved via settlement and the remaining open issues were submitted to the PUCT. A final order was issued by the PUCT in February 2001 and adjustments to the accrued 1999 and 2000 excess earnings were recorded in results of operations in the fourth quarter of 2000. After adjustments the accruals for 1999 excess earnings for CPL and WTU were $24 million and $1 million, respectively. CPL and WTU also recorded an estimated provision for excess 2000 earnings of $16 million and $14 million, respectively.

A Texas settlement agreement in connection with the AEP and CSW merger permits CPL to apply for regulatory purposes up to $20 million of STP ECOM plant assets a year in 2000 and 2001 to reduce excess earnings, if any. For book and financial reporting purposes, STP ECOM plant assets will be depreciated in accordance with GAAP, on a systematic and rational basis unless impaired. CPL will establish a regulatory liability or reduce regulatory assets by a charge to earnings to the extent excess earnings exceed $20 million in 2000 and 2001.

Beginning January 1, 2002, fuel costs will not be subject to PUCT fuel reconciliation proceedings. Consequently, CPL, SWEPCo and WTU will file a final fuel reconciliation with the PUCT to reconcile their fuel costs through the period ending December 31, 2001. Fuel costs have been reconciled by CPL, SWEPCo and WTU through June 30, 1998, December 31, 1999 and June 30, 1997, respectively. WTU is currently reconciling its fuel through June 2000. See discussion in Note 5 of the Notes to Consolidated Financial Statements. At December 31, 2000, CPL's, SWEPCo's and WTU's Texas jurisdictional unrecovered deferred fuel balances were $127 million, $20 million and $59 million, respectively. Final unrecovered deferred fuel balances at December 31, 2001 will be included in each company's 2004 true-up proceeding. If the final fuel balances or any amount incurred but not yet reconciled were not recovered, they could have a negative impact on results of operations. The elimination of the fuel clause recoveries in 2002 in Texas will subject AEP, CPL, SWEPCo and WTU to greater risks of fuel market price increases and could adversely affect future results of operations beginning in 2002.

The affiliated retail electric provider of CPL, SWEPCo and WTU will be required to offer residential and small commercial customers (with a peak usage of less than 1000 KW) a rate 6% below rates in effect on January 1, 1999 adjusted for any changes in fuel cost recovery factors since January 1, 1999 (price to beat). The price to beat must be offered to residential and small commercial customers until January 1, 2007. Customers with a peak usage of more than 1000 KW are subject to market rates. The Texas restructuring legislation provides for the price to beat to be adjusted up to two times annually to reflect significant changes in fuel and purchased energy costs.

*CPL, SWEPCo and WTU Discontinue Application of SFAS 71 Regulatory Accounting in Arkansas and Texas*

The financial statements of CPL, SWEPCo and WTU have historically reflected the economic effects of regulation by applying the requirements of SFAS 71. As a result of the scheduled deregulation of generation in Arkansas and Texas, the application of SFAS 71 for the generation portion of the business in those states was discontinued in the third quarter of 1999. Under the provisions of EITF 97-4, CPL's generation-related net regulatory assets were transferred to the distribution portion of the business and will be amortized as they are recovered through wires charges to customers. Management believes that substantially all of CPL's generation-related regulatory assets will be recovered under the Texas Legislation. CPL's recovery of generation-related regulatory assets and stranded costs are subject to a final determination by the PUCT in 2004. If future events were to make the recovery through securitization of CPL's generation-related regulatory assets no longer probable, CPL would write-off the portion of such regulatory assets deemed unrecoverable as a non-cash extraordinary charge to earnings.

The Texas Legislation provides that all finally determined stranded costs will be recovered. Since SWEPCo and WTU are not expected to have net stranded costs, all Arkansas and Texas jurisdictional generation-related net regulatory assets were written off as non-recoverable in 1999 when they discontinued application of SFAS 71 regulatory accounting. As required by SFAS 101 when SFAS 71 is discontinued, an accounting impairment analysis for generation assets under SFAS 121 was completed for CPL, SWEPCo and WTU. The analysis showed that there was no accounting impairment of generation assets when the application of SFAS 71 was discontinued. CPL, SWEPCo and WTU will test their generation assets for impairment under SFAS 121 if circumstances change. Management believes that on a discounted basis CPL's generation business net cash flows will likely be less than its generating assets' net book value and together with its generation-related regulatory assets should create a recoverable stranded cost for regulatory purposes under the Texas Legislation. Therefore, management continues to carry on the balance sheet at December 31, 2000, $953 million of generation-related regulatory assets already approved for securitization and $195 million of net generation-related regulatory assets pending approval for securitization in Texas. A final determination of whether they will be securitized and recovered will be made as part of the 2004 true-up proceeding.

CPL, SWEPCo, and WTU continue to analyze the impact of electric utility industry restructuring legislation on their Arkansas and Texas electric operations. Although management believes that the Texas Legislation provides for full recovery of stranded costs and that the companies do not have a recordable accounting impairment, a final determination of whether CPL will experience an accounting loss or whether SWEPCo and WTU will experience any additional accounting loss from an inability to recover generation-related regulatory assets and other restructuring related costs in Texas and Arkansas cannot be made until such time as the regulatory process is complete following the 2004 true-up proceeding in Texas and a determination by the Arkansas Commission. In the event CPL, SWEPCo, and WTU are unable after the 2004 true-up proceeding and after the Arkansas

Commission proceedings to recover all or a portion of their generation-related regulatory assets, stranded costs and other restructuring related costs, it could have a material adverse effect on results of operations, cash flows and possibly financial condition.

Although Arkansas' delay of retail competition may be having a negative effect on the progress of efforts to transition SWEPCo's generation in Arkansas to market based pricing of electricity, it appears that Texas is moving forward as planned. Management is carefully monitoring the situation in Arkansas and is working with all concerned parties to prudently quicken the pace of the transition. However, changes could occur due to concerns stemming from the California energy crisis and other events which could adversely affect future results of operations in Arkansas and possibly Texas.

*Michigan Restructuring – Affecting AEP and I&M*

On June 5, 2000, the Michigan Legislation became law. Its major provisions, which were effective immediately, applied only to electric utilities with one million or more retail customers. I&M, AEP's electric operating subsidiary doing business in Michigan, has less than one million customers in Michigan. Consequently, I&M was not immediately required to comply with the Michigan Legislation.

The Michigan Legislation gives the MPSC broad power to issue orders to implement retail customer choice of electric supplier no later than January 1, 2002 including recovery of regulatory assets and stranded costs. On October 2, 2000, I&M filed a restructuring implementation plan as required by a MPSC order. The plan identifies I&M's proposal to file with the MPSC on June 5, 2001 its unbundled rates, open access tariffs, terms of service and supporting schedules. Described in the plan are I&M's intentions and preparation for competition related to supplier transactions, customer transactions, rate unbundling, education programs, and regional transmission organization. The plan contains a proposed methodology to determine stranded costs and implementation costs and requests the continuation of a wires charge for recovery of nuclear decommissioning costs. Approval of the restructuring implementation plan is pending before the MPSC.

Management has concluded that as of December 31, 2000 the requirements to apply SFAS 71 continue to be met since I&M's rates for generation in Michigan will continue to be cost-based regulated until the MPSC approves rates and wires charges in 2001. The establishment of rates and wires charges under a MPSC approved transition plan will enable management to determine the ability to recover stranded costs including regulatory assets and other implementation costs, a requirement of EITF 97-4 to discontinue the application of SFAS 71.

Upon the discontinuance of SFAS 71, I&M will, if necessary, have to write off its Michigan jurisdictional generation-related regulatory assets and record its unrecorded Michigan jurisdictional liability for decommissioning the Cook Plant to the extent that they cannot be recovered under the transition rates and wires charges. As required by SFAS 101 when discontinuing SFAS 71 regulatory accounting, I&M will have to perform an accounting impairment analysis under SFAS 121 to determine if the Michigan jurisdictional portion of its generating assets are impaired for accounting purposes.

The amount of regulatory assets recorded on the books at December 31, 2000 applicable to I&M's Michigan retail jurisdictional generation business is approximately $45 million before related tax effects. The estimated unrecorded liability for the Michigan jurisdiction to decommission the Cook Plant ranges from $114 million to $215 million in 2000 non-discounted dollars based upon studies completed during 2000. For the Michigan jurisdiction, I&M has accumulated approximately $100 million in trust funds to decommission the Cook Plant. Based on the current information available, management does not anticipate that I&M will experience any material tangible asset accounting impairment or regulatory asset write-offs. Ultimately, however, whether I&M will experience material regulatory asset write-offs will depend on whether the MPSC approves their recovery in future restructuring proceedings.

A determination of whether I&M will experience any asset impairment loss regarding its Michigan retail jurisdictional generating assets and any loss from a possible inability to recover Michigan generation-related regulatory assets, decommissioning obligations and transition costs cannot be made until such time as the rates and the wires charges are determined through the regulatory process. In the event I&M is unable to recover all or a portion of its generation-related regulatory assets, unrecorded decommissioning obligation, stranded costs and other implementation costs, it could have a material adverse effect on results of operations, cash flows and possibly financial condition.

*Oklahoma Restructuring – Affecting AEP and PSO*

In 1997, the Oklahoma Legislature passed restructuring legislation providing for retail open access by July 1, 2002. That legislation called for a number of studies to be completed on a variety of restructuring issues, including an independent system operator, technical, financial, transition and consumer issues. During 1998 and 1999 several of the studies were completed.

The information from the studies was expected to be used in the development of additional industry restructuring legislation during the 2000 legislative session. Several additional electric industry restructuring bills were filed in the 2000 Oklahoma legislative session. The proposed bills generally supplemented the industry restructuring legislation previously enacted in Oklahoma which lacked specific procedures for a transition to market based competitive prices. The industry restructuring legislation previously passed did not delegate the establishment of transition procedures to the Oklahoma Corporation Commission. The 2000 Oklahoma legislative session adjourned in May without passing further restructuring legislation.

The 2001 Oklahoma legislative session convened in early February. No further electric restructuring legislation has passed and proposals have been made to delay the implementation of the transition to customer choice and market based pricing under the restructuring legislation. These proposals are a reaction to California's recent energy crisis. Management is working with all concerned parties to reassure them that what happened in California will not occur in Oklahoma. If the necessary legislation is not passed, PSO's generation and retail electric supply business will remain regulated in Oklahoma. If implementation legislation were to modify the original restructuring legislation in Oklahoma it could have a adverse effect on results of operations.

Management has concluded that as of December 31, 2000 the requirements to apply SFAS 71 continue to be met since PSO's rates for generation in Oklahoma will continue to be cost-based regulated until the Oklahoma Legislature approves further restructuring legislation and transition rates and wires charges are established under an approved transition plan. Until management is able to determine the ability to recover stranded costs which includes regulatory assets and other implementation costs, PSO cannot discontinue application of SFAS 71 accounting under GAAP.

When PSO discontinues application of SFAS 71, it will be necessary to write off Oklahoma jurisdictional generation-related regulatory assets to the extent that they cannot be recovered under the transition rates and wires charges, when determined, and record any asset accounting impairments in accordance with SFAS 121.

A determination of whether PSO will experience any asset impairment loss regarding its Oklahoma retail jurisdictional generating assets and any loss from a possible inability to recover Oklahoma generation-related regulatory assets and other transition costs cannot be made until such time as the rates and the wires charges are determined through the legislative and/or regulatory process. In the event PSO is unable to recover all or a portion of its generation-related regulatory assets and implementation costs, Oklahoma restructuring could have a material adverse effect on results of operations and cash flows.

*Restructuring In Other Jurisdictions*

The remaining four states (Indiana, Kentucky, Louisiana and Tennessee) making up AEP's service territory have initiatives to implement or review customer choice, although the timing of any implementation is uncertain and may be further delayed due to the California situation. AEP supports customer choice and deregulation of generation and is proactively involved in discussions regarding the best competitive market structure and transition method to arrive at a fair, competitive marketplace. As the pricing of generation in these markets evolves from regulated cost-of-service rates to market-based pricing, the recovery of stranded costs including net regulatory assets and other transition costs must be addressed. The amount of stranded costs the AEP subsidiaries could experience when and if restructuring occurs in their state jurisdictions depends on the timing and extent to which competition is introduced to their business and the future market prices of electricity. The recovery of stranded cost is dependent on the terms of future legislation and, if required, related regulatory proceedings.

Customer choice and the transition to market based competition if restructuring is implemented in Indiana, Kentucky, Louisiana and Tennessee could also ultimately result in adverse impacts on results of operations and cash flows depending on the future market prices of electricity and the ability of the subsidiaries to recover their stranded costs including net regulatory assets during a transition or subsequent period through a wires charge or other recovery mechanism. Management believes that state restructuring legislation and the regulatory process should provide for full recovery of generation-related net regulatory assets and other reasonable stranded costs if these states decide to deregulate generation. However, if in the future any portion of the generation business in these other jurisdictions were to no longer be cost-based regulated and if it were not possible to demonstrate probability of recovery of resultant stranded costs including regulatory assets, results of operations, cash flows and financial condition would be adversely affected.

*Amortization of Transition Regulatory Assets and Other Deferred Costs – Affecting AEP, APCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo and WTU*

Future earnings will be negatively impacted by amortization of certain deferred costs and regulatory assets related to I&M's Cook Plant extended outage, transition plans to discontinue SFAS 71 regulatory accounting for generation with the beginning of customer choice in certain states and the merger of AEP and CSW.

During 1999, the IURC and MPSC approved settlement agreements which provided for the deferral in 1999 and amortization of restart costs and fuel-related revenues from the extended Cook Plant outage. The amortization period is for five years ending in December 2003. Annual amortization is $78 million for I&M. See Note 4 of the Notes to Consolidated Financial Statements.

Beginning in 2001 under the Ohio Act, CSPCo and OPCo began amortizing their transition regulatory assets over eight and seven years, respectively. The annual amortization in 2001 for CSPCo and OPCo is estimated to be $20 million and $74 million, respectively. The amount of amortization is based upon KWH sold.

APCo began amortization of its West Virginia jurisdictional regulatory assets over an eleven year period in July 2000. In the Virginia jurisdiction, APCo started straight line amortization of regulatory assets over a seven year period in July 2000. The annual amortization for 2001 is $9 million for APCo's West Virginia jurisdiction and $9 million for APCo's Virginia jurisdiction.

In June 2000 AEP merged with CSW. In connection with securing approval for the merger, AEP and certain of its subsidiaries signed agreements, approved by regulatory authorities, which included rate reductions to share estimated merger savings with customers. The agreements provide for rate reductions for periods up to eight years beginning in the third quarter of 2000.

Certain merger related costs recoverable from ratepayers were deferred pursuant to the settlement agreements and will be amortized over five to eight years depending upon the terms of the respective agreements. The annual amortization of the deferred merger costs for the AEP System is estimated to total $8 million in 2001. The merger amortization will be recorded as follows: $2.6 million by CPL, $1.7 million by I&M, $600,000 by KPCo, $1.2 million by PSO, $1.1 million by SWEPCo and $800,000 by WTU. If actual merger savings are significantly less than the merger savings rate reductions required by the merger settlement agreements and the amortization of deferred merger-related costs, future results of operations, cash flows and possibly financial condition could be adversely affected. See Note 3 of the Notes to Consolidated Financial Statements for further discussion of the merger.

Amortization of the above described deferred costs and regulatory assets could negatively affect future earnings to the extent that they exceed cost savings or revenues growth.

**Litigation**

*COLI – Affecting AEP, APCo, CSPCo, I&M, KPCo and OPCo*

On February 20, 2001, the U.S. District Court for the Southern District of Ohio ruled against AEP in its suit against the United States over deductibility of interest claimed by AEP in its consolidated federal income tax return related to its COLI program. AEP had filed suit to resolve the IRS' assertion that interest deductions for AEP's COLI program should not be allowed. In 1998 and 1999 AEP and the impacted subsidiaries paid the disputed taxes and interest attributable to COLI interest deductions for taxable years 1991-98 for APCo, CSPCo, I&M and OPCo and 1992-98 for KPCo to avoid the potential assessment by the IRS of additional interest on the contested tax. The payments were included in other assets on AEP Consolidated Balance Sheet and Other Property and Investments on the subsidiaries' balance sheets pending the resolution of this matter. As a result of the U.S. District Court's decision to deny the COLI interest deductions, net income was reduced by $319 million for the AEP System in 2000. Management plans to appeal the decision.

The earnings reductions for affected registrant subsidiaries are as follows:

| | (in millions) |
|---|---|
| APCo | $ 82 |
| CSPCo | 41 |
| I&M | 66 |
| KPCo | 8 |
| OPCo | 118 |

*Shareholders' Litigation – Affecting AEP*

On June 23, 2000, a complaint was filed in the U.S. District Court for the Eastern District of New York seeking unspecified compensatory damages against AEP and four former or present officers. The individual plaintiff also seeks certification as the representative of a class consisting of all persons and entities who purchased or otherwise acquired AEP common stock between July 25, 1997, and June 25, 1999. The complaint alleges that the defendants knowingly violated federal securities laws by disseminating materially false and misleading statements concerning, among other things, the undisclosed materially impaired condition of the Cook Plant, AEP's inability to properly monitor, manage, repair, supervise and report on operations at the Cook Plant and the materially adverse conditions these problems were having, and would continue to have, on AEP's deteriorating financial condition, and ultimately on AEP's operations, liquidity and stock price. Four other similar class action complaints have been filed and the court has consolidated the five cases. The plaintiffs filed a consolidated complaint pursuant to this court order. This case has been transferred to the U.S. District Court for the Southern

District of Ohio. Although, management believes these shareholder actions are without merit and intends to oppose them vigorously, management cannot predict the outcome of this litigation or its impact on results of operations, cash flows or financial condition.

*Municipal Franchise Fee Litigation – Affecting AEP and CPL*

CPL has been involved in litigation regarding municipal franchise fees in Texas as a result of a class action suit filed by the City of San Juan, Texas in 1996. The City of San Juan claims CPL underpaid municipal franchise fees and seeks damages of up to $300 million plus attorney's fees. CPL filed a counterclaim for overpayment of franchise fees.

During 1997, 1998 and 1999 the litigation moved procedurally through the Texas Court System and was sent to mediation without resolution.

In 1999 a class notice was mailed to each of the cities served by CPL. Over 90 of the 128 cities declined to participate in the lawsuit. However, CPL has pledged that if any final, non-appealable court decision awards a judgement against CPL for a franchise underpayment, CPL will extend the principles of that decision, with regard to any franchise underpayment, to the cities that declined to participate in the litigation. In December 1999, the court ruled that the class of plaintiffs would consist of approximately 30 cities. A trial date for June 2001 has been set.

Although management believes that it has substantial defenses to the cities' claims and intends to defend itself against the cities' claims and pursue its counterclaim vigorously, management cannot predict the outcome of this litigation or its impact on results of operations, cash flows or financial condition.

*Texas Base Rate Litigation – Affecting AEP and CPL*

In November 1995 CPL filed with the PUCT a request to increase its retail base rates by $71 million. In October 1997 the PUCT issued a final order which lowered CPL's annual retail base rates by $19 million from the rate level which existed prior to May 1996. The PUCT also included a "glide path" rate methodology in the final order pursuant to which annual rates were reduced by $13 million beginning May 1, 1998 with an additional annual reduction of $13 million commencing on May 1, 1999.

CPL appealed the final order to the Travis District Court. The primary issues being appealed include: the classification of $800 million of invested capital in STP as ECOM and assigning it a lower return on equity than other generation property; the use of the "glide path" rate reduction methodology; and an $18 million disallowance of service billings from an affiliate, CSW Services. As part of the appeal, CPL sought a temporary injunction to prohibit the PUCT from implementing the "glide path" rate reduction methodology. The temporary injunction was denied and the "glide path" rate reduction was implemented. In February 1999 the Travis District Court affirmed the PUCT order in regard to the three major items discussed above.

CPL appealed the Travis District Court's findings to the Texas Appeals Court which in July 2000, issued its opinion upholding the Travis District Court except for the disallowance of affiliated service company billings. Under Texas law, specific findings regarding affiliate transactions must be made by PUCT. In regards to the affiliate service billing issue, the findings were not complete in the opinion of the Texas Appeals Court who remanded the issue back to PUCT.

CPL has sought a rehearing of the Texas Appeals Court's opinion. The Texas Appeals Court has requested briefs related to CPL's rehearing request from interested parties. Management is unable to predict the final resolution of its appeal. If the appeal is unsuccessful the PUCT's 1997 order will continue to adversely affect results of operations and cash flows.

As part of the AEP/CSW merger approval process in Texas, a stipulation agreement was approved which resulted in the withdrawal of the appeal related to the "glide path" rate methodology. CPL will continue its appeal of the ECOM classification for STP property and the related loss of return on equity and the disallowed affiliated service billings.

*Lignite Mining Agreement Litigation – Affecting AEP and SWEPCo*

SWEPCo and CLECO are each a 50% owner of Dolet Hills Power Station Unit 1 and jointly own lignite reserves in the Dolet Hills area of northwestern Louisiana. In 1982, SWEPCo and CLECO entered into a lignite mining agreement with DHMV, a partnership for the mining and delivery of lignite from a portion of these reserves.

In April 1997, SWEPCo and CLECO sued DHMV and its partners in U.S. District Court for the Western District of Louisiana seeking to enforce various obligations of DHMV under the lignite mining agreement, including provisions relating to the quality of delivered lignite, pricing, and mine reclamation practices. In June 1997, DHMV filed an answer denying the allegations in the suit and filed a counterclaim asserting various contract-related claims against SWEPCo and CLECO. SWEPCo and CLECO have denied the allegations contained in the counterclaims. In January 1999, SWEPCo and CLECO amended the claims against DHMV to include a request that the lignite mining agreement be terminated.

In April 2000, the parties agreed to settle the litigation. As part of the settlement, DHMV's interest in the mining operations and related debt and other obligations will be purchased by SWEPCo and CLECO. The closing date for the settlement has been extended from December 31, 2000 to March 31, 2001. The litigation has been stayed until April 2001 to give the parties time to consummate the settlement agreement.

Management believes that the resolution of this matter will not have a material effect on results of operations, cash flows or financial condition.

AEP and its registrant subsidiaries are involved in a number of other legal proceedings and claims. While management is unable to predict the outcome of such litigation, it is not expected that the ultimate resolution of these matters will have a material adverse effect on the results of operations, cash flows or financial condition.

**Environmental Concerns and Issues**

As 2001 begins, the U.S. continues to debate an array of environmental issues affecting the electric utility industry. Most of the policies are aimed at reducing air emissions citing alleged impacts of such emissions on public health, sensitive ecosystems or the global climate.

AEP and its subsidiaries' policy on the environment continues to be the development and application of long-term economically feasible measures to improve air and water quality, limit emissions and protect the health of employees, customers, neighbors and others impacted by their operations. In support of this policy, AEP and its subsidiaries continue to invest in research through groups like the Electric Power Research Institute and directly through demonstration projects for new technology for the capture and storage of carbon dioxide, mercury, NOx and other emissions. The AEP System intends to continue in a leadership role to protect and preserve the environment while providing vital energy commodities and services to customers at fair prices.

AEP and its subsidiaries have a proven record of efficiently producing and delivering electricity and gas while minimizing the impact on the environment. AEP and its subsidiaries have spent billions of dollars to equip their facilities with the latest cost effective clean air and water technologies and to research new technologies. Award winning efforts to reclaim our mining properties is a proud accomplishment.

The introduction of multi-pollutant control legislation is being discussed by members of Congress and the Bush Administration. The legislation being considered may regulate carbon dioxide, NOx, sulfur dioxide, mercury and other emissions from electric generating plants. Management will continue to support solutions which are based on sound science, economics and demonstrated control technologies. Management is unable to predict the timing or magnitude of additional pollution control laws or regulations. If additional control technology is required on facilities owned by the electric utility companies and their costs were not recoverable from ratepayers or through market based prices or volumes of product sold, they could adversely affect future results of operations and cash flows. The following discussions explains existing control efforts, litigation and other pending matters related to environmental issues for AEP System companies.

*Federal EPA Complaint and Notice of Violation – Affecting AEP, APCo, CSPCo, I&M and OPCo*

Under the Clean Air Act, if a plant undertakes a major modification that directly results in an emissions increase, permitting requirements might be triggered and the plant may be required to install additional pollution control technology. This requirement does not apply to activities such as routine maintenance, replacement of degraded equipment or failed components, or other repairs needed for the reliable, safe and efficient operation of the plant.

AEP, APCo, CSPCo, I&M and OPCo have been involved in litigation regarding generating plant emissions under the Clean Air Act. In 1999 Notices of Violation were issued and complaints were filed by Federal EPA in various U.S. District Courts alleging APCo, CSPCo, I&M and OPCo and a number of unaffiliated utilities made modifications to generating units at certain of their coal-fired generating plants over the course of the past 25 years that extended unit operating lives or increased unit generating capacity without a preconstruction permit in violation of the Clean Air Act. The complaint was amended in March 2000 to add allegations for certain generating units previously named in the complaint and to include additional generating units previously named only in the Notices of Violation in the complaint.

A number of northeastern and eastern states were granted leave to intervene in the Federal EPA's action against the AEP System under the Clean Air Act. A lawsuit against power plants owned by certain AEP System operating companies alleging similar violations to those in the Federal EPA complaint and Notices of Violation was filed by a number of special interest groups and has been consolidated with the Federal EPA action.

The Clean Air Act authorizes civil penalties of up to $27,500 per day per violation at each generating unit ($25,000 per day prior to January 30, 1997). Civil penalties, if ultimately imposed by the court, and the cost of any required new pollution control equipment, if the court accepts Federal EPA's contentions, could be substantial.

On May 10, 2000, the AEP System companies filed motions to dismiss all or portions of the complaints. Briefing on these motions was completed on August 2, 2000. On February 23, 2001, the government filed a motion for partial summary judgement seeking a determination that four projects undertaken on units at Sporn, Cardinal and Clinch River plants do not constitute "routine maintenance, repair and replacement" as used in the Clear Air Act. Management believes its maintenance, repair and replacement activities were in conformity with the Clean Air Act and intends to vigorously pursue its defense.

In the event the AEP System companies do not prevail, any capital and operating costs of additional pollution control equipment that may be required as well as any penalties imposed would adversely affect future results of operations, cash flows and possibly financial condition unless such costs can be recovered through regulated rates, and where states are deregulating generation, unbundled transition period generation rates, stranded cost wires charges and future market prices for electricity.

In December 2000 Cinergy Corp., an unaffiliated utility, which operates certain plants jointly owned by AEP's subsidiary, CSPCo, reached a tentative agreement with Federal EPA and other parties to settle litigation regarding generating plant emissions under the Clean Air Act. Negotiations are continuing between the parties in an attempt to reach final settlement terms. Cinergy's settlement could impact the operation of

Zimmer Plant and W.C. Beckjord Generating Station Unit 6 which are owned 25.4% and 12.5%, respectively, by CSPCo. Until a final settlement is reached, CSPCo will be unable to determine the settlement's impact on its jointly owned facilities and its future earnings and cash flows.

*NOx Reduction – Affecting AEP, APCo, CPL, I&M, OPCo and SWEPCo*

Federal EPA issued a NOx rule that required substantial reductions in NOx emissions in a number of eastern states, including certain states in which the AEP System's generating plants are located. A number of utilities, including several AEP System companies, filed petitions seeking a review of the final rule in the D.C. Circuit Court. In March 2000, the D.C. Circuit Court issued a decision generally upholding the NOx rule. The D.C. Circuit Court issued an order in August 2000 which extends the final compliance date to May 31, 2004. In September 2000 following denial by the D.C. Circuit Court of a request for rehearing, the industry petitioners, including the AEP System companies, petitioned the U.S. Supreme Court for review, which was denied.

In December 2000 Federal EPA ruled that eleven states, including certain states in which the AEP System's generating units are located, failed to submit plans to comply with the mandates of the NOx rule. This determination means that those states could face stringent sanctions within the next 24 months including limits on construction of new sources of air emissions, loss of federal highway funding and possible Federal EPA takeover of state air quality management programs.

In January 2000 Federal EPA adopted a revised rule granting petitions filed by certain northeastern states under Section 126 of the Clean Air Act seeking significant reductions in nitrogen oxide emissions from utility and industrial sources. The rule imposes emissions reduction requirements comparable to the NOx rule beginning May 1, 2003, for most of AEP's coal-fired generating units. Certain AEP companies and other utilities filed petitions for review in the D.C. Circuit Court. Briefing has been completed and oral argument was held in December 2000.

In a related matter, on April 19, 2000, the Texas Natural Resource Conservation Commission adopted rules requiring significant reductions in NOx emissions from utility sources, including CPL and SWEPCo. The rule's compliance date is May 2003 for CPL and May 2005 for SWEPCo.

In June 2000 OPCo announced that it was beginning a $175 million installation of selective catalytic reduction technology (expected to be operational in 2001) to reduce NOx emissions on its two-unit 2,600 MW Gavin Plant. Construction of selective catalytic reduction technology on Amos Plant Unit 3, which is jointly owned by OPCo and APCo, and APCo's Mountaineer Plant is scheduled to begin in 2001. The Amos and Mountaineer projects (expected to be completed in 2002) are estimated to cost a total of $230 million ($145 million for APCo and $85 million for OPCo).

Preliminary estimates indicate that compliance with the NOx rule upheld by the D.C. Circuit Court as well as compliance with the Texas Natural Resource Conservation Commission rule and the Section 126 petitions could result in required capital expenditures of approximately $1.6 billion including the amounts discussed in the previous paragraph for the AEP System.

The following table shows the estimated compliance cost for certain of AEP's registrant subsidiaries.

| Company | Amount (in millions) |
|---|---|
| APCo | $365 |
| CPL | 57 |
| I&M | 202 |
| OPCo | 606 |
| SWEPCo | 28 |

Since compliance costs cannot be estimated with certainty, the actual cost to comply could be significantly different than the preliminary estimates depending upon the compliance alternatives selected to achieve reductions in NOx emissions. Unless any capital and operating costs of additional pollution control equipment are recovered from customers through regulated rates and/or future market prices for electricity where generation is deregulated, they will have an adverse effect on future results of operations, cash flows and possibly financial condition.

*Superfund – Affecting AEP, APCo, CPL, CSPCo, I&M, OPCo and SWEPCo*

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 disposed of or treated in captive disposal facilities or are beneficially utilized. In addition, the AEP System's generating plants and transmission and distribution facilities have used asbestos, PCBs and other hazardous and non-hazardous materials. The AEP System companies are currently incurring costs to safely dispose of these substances. Additional costs could be incurred to comply with new laws and regulations if enacted.

Superfund addresses clean-up of hazardous substances at disposal sites and authorized Federal EPA to administer the clean-up programs. As of year-end 2000, subsidiaries of AEP have been named by the Federal EPA as a PRP for five sites. APCo, CSPCo, and OPCo each have one PRP site and I&M has two PRP sites. There are five additional sites for which AEP, APCo, CSPCo, I&M, OPCo and SWEPCo have received information requests which could lead to PRP designation. CPL, OPCo and SWEPCo have also been named a PRP at three sites under state law. Liability has been resolved for a number of sites with no significant effect on the AEP subsidiaries' results of operations. In those instances where AEP or its subsidiaries have been named a PRP or defendant, their disposal or recycling activities were in accordance with the then-applicable laws and regulations. Unfortunately, Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories.

While the potential liability for each Superfund site must be evaluated separately, several general statements can be made regarding AEP's and its subsidiaries' potential future liability. Disposal of materials at a particular site is often unsubstantiated and the quantity of materials deposited at a site was small and often nonhazardous. Although liability is joint and several, typically many parties are named as PRPs for each site and several of the parties are financially sound enterprises. Therefore, management's present estimates do not anticipate material cleanup costs for identified sites for which AEP System companies have been declared PRPs. If significant cleanup costs are attributed to AEP or its subsidiaries in the future under Superfund, results of operations, cash flows and possibly financial condition would be adversely affected unless the costs can be recovered from customers.

*Global Climate Change*

At the Third Conference of the Parties to the United Nations Framework Convention on Climate Change held in Kyoto, Japan in December 1997 more than 160 countries, including the U.S., negotiated a treaty requiring legally-binding reductions in emissions of greenhouse gases, chiefly carbon dioxide, which many scientists believe are contributing to global climate change. The treaty, which requires the advice and consent of the U.S. Senate for ratification, would require the U.S. to reduce greenhouse gas emissions seven percent below 1990 levels in the years 2008-2012. Although the U.S. has agreed to the treaty and signed it on November 12, 1998, the treaty has not been submitted to the Senate for consideration as it does not contain requirements for "meaningful participation by key developing countries" and the rules, procedures, methodologies and guidelines of the treaty's emissions trading and joint implementation programs and compliance enforcement provisions have not been negotiated. At the Fourth Conference of the Parties in November 1998, the parties agreed to a work plan to complete negotiations on outstanding issues with a view toward approving them at the Sixth Conference of the Parties to be held in November 2000. During the Sixth Conference of the Parties agreement was not reached on any of the outstanding issues requiring resolution in order to faciliate ratification of the Kyoto Protocol. There are several contentious issues and literally hundreds of pages of detailed, complex rules that remain to be negotiated. Discussions are expected to resume in July 2001. While a candidate for the presidency, George Bush had stated his opposition to U.S. ratification of the Kyoto Protocol. The Seventh Conference of the Parties is scheduled for October 2001 in Morocco. AEP does not support the Kyoto Treaty as presently drafted. Management will continue to work with the Administration and Congress to develop responsible public policy on this issue.

If the Kyoto treaty is approved by Congress as presently drafted, the costs for the AEP System to comply with the required emission reductions required by the treaty are expected to be substantial and would have a material adverse impact on results of operations, cash flows and possibly financial condition if not recovered from customers. It is management's belief that the Kyoto Protocol is unlikely to be ratified and implemented in the U.S. in its current form.

*Costs for Spent Nuclear Fuel and Decommissioning – Affecting AEP, CPL and I&M*

I&M, as the owner of the Cook Plant, and CPL, as a partial owner of STP, have a significant future financial commitment to safely dispose of SNF and decommission and decontaminate the plants. The Nuclear Waste Policy Act of 1982 established federal responsibility for the permanent off-site disposal of SNF and high-level radioactive waste. By law CPL and I&M participate in the DOE's SNF disposal program which is described in Note 8 of the Notes to Consolidated Financial Statements. Since 1983 I&M has collected $275 million from customers for the disposal of nuclear fuel consumed at the Cook Plant. $116 million of these funds have been deposited in external trust funds to provide for the future disposal of SNF and $159 million has been remitted to the DOE. CPL has collected and remitted to the DOE, $44 million for the future disposal of SNF since STP began operation in the late 1980s. Under the provisions of the Nuclear Waste Policy Act, collections from customers are to provide the DOE with money to build a permanent repository for spent fuel. However, in 1996, the DOE notified the companies that it would be unable to begin accepting SNF by the January 1998 deadline required by law. To date DOE has failed to comply with the requirements of the Nuclear Waste Policy Act.

As a result of DOE's failure to make sufficient progress toward a permanent repository or otherwise assume responsibility for SNF, AEP on behalf of I&M and STPNOC on behalf of CPL and the other STP owners, along with a number of unaffiliated utilities and states, filed suit in the D.C. Circuit Court requesting, among other things, that the D.C. Circuit Court order DOE to meet its obligations under the law. The D.C. Circuit Court ordered the parties to proceed with contractual remedies but declined to order DOE to begin accepting SNF for disposal. DOE estimates its planned site for the nuclear waste will not be ready until at least 2010. In 1998, AEP and I&M filed a complaint in the U.S. Court of Federal Claims seeking damages in excess of $150 million due to the DOE's partial material breach of its unconditional contractual deadline to begin disposing of SNF generated by the Cook Plant. Similar lawsuits were filed by other utilities. In August 2000, in an appeal of related cases involving other unaffiliated utilities, the U.S. Court of Appeals for the Federal Circuit held that the delays clause of the standard contract between utilities and the DOE did not apply to DOE's complete failure to perform its contract obligations, and that the utilities' suits against DOE may continue in court. AEP's and I&M suit has been stayed pending further action by the U.S. Court of Federal Claims. As long as the delay in the availability of a government approved storage repository for SNF continues, the cost of both temporary and permanent storage and the cost of decommissioning will continue to increase.

In January 2001, I&M and STPNOC, on behalf of STP's joint owners, joined a lawsuit against DOE, filed in November 2000 by unaffiliated utilities, related to DOE's nuclear waste fund cost recovery settlement with PECO Energy Corporation. The settlement allows PECO to skip two payments to the DOE for disposal of SNF due to the lack of progress towards development of a permanent repository for SNF. The companies believe the settlement is unlawful as the settlement would force other utilities to make up any shortfall in DOE's SNF disposal funds.

The cost to decommission nuclear plants is affected by both NRC regulations and the delayed SNF disposal program. Studies completed in 2000 estimate the cost to decommission the Cook Plant ranges from \$783 million to \$1,481 million in 2000 non-discounted dollars. External trust funds have been established with amounts collected from customers to decommission the plant. At December 31, 2000, the total decommissioning trust fund balance for Cook Plant was \$558 million which includes earnings on the trust investments. Studies completed in 1999 for STP estimate CPL's share of decommissioning cost to be \$289 million in 1999 non-discounted dollars. Amounts collected from customers to decommission STP have been placed in an external trust. At December 31, 2000, the total decommissioning trust fund for CPL's share of STP was \$94 million which includes earnings on the trust investments. Estimates from the decommissioning studies could continue to escalate due to the uncertainty in the SNF disposal program and the length of time that SNF may need to be stored at the plant site. We will work with regulators and customers to recover the remaining estimated costs of decommissioning Cook Plant and STP through regulated rates and, where generation has been deregulated, through wires charges. However, AEP's, CPL's and I&M's future results of operations, cash flows and possibly their financial conditions would be adversely affected if the cost of SNF disposal and decommissioning continues to increase and cannot be recovered.

### Foreign Energy Delivery, Worldwide Energy Investments and Other Business Operations

Worldwide electric and gas operations on AEP's Consolidated Statements of Income include the foreign energy delivery, worldwide energy investments, and other segments of AEP's business. See Note 14 of the Notes to Consolidated Financial Statements for a discussion of segments.

AEP's investment in certain types of activities is limited by PUHCA. SEC authorization under PUHCA limits AEP to issuing and selling securities in an amount up to 100% of its average quarterly consolidated retained earnings balance for investment in EWGs and FUCOs. At December 31, 2000, AEP's investment in EWGs and FUCOs was \$1.8 billion compared to AEP's limit of \$3.4 billion by law.

SEC rules under PUHCA permit AEP to invest up to 15% of consolidated capitalization (such amount was \$3.5 billion at December 31, 2000) in energy-related companies that engage in marketing and/or trading of electricity, gas and other energy commodities. AEP's gas trading business and its interests in domestic cogeneration projects are reported as investments under this rule and at December 31, 2000, AEP's investment was less than one million dollars.

Management continues to evaluate the U.S. and international energy markets for investment opportunities that complement AEP's wholesale operations. Management expects to continue to pursue new and existing energy supply projects and to provide energy related services worldwide. AEP's future consolidated earnings will be impacted by the performance of existing and any future investments.

The major business activities and subsidiaries of AEP's worldwide electric and gas operations are SEEBOARD, CitiPower, Yorkshire, European energy trading operations, U.S. power trading more than two transmission systems removed from the AEP transmission system and gas trading operations in the U.S., domestic and foreign generating facilities in China, Mexico and the U.S., electric distribution in South America and power plant construction. SEEBOARD's principal business is the distribution and supply of electricity in southeast England. CitiPower provides electricity and electric distribution service in the city of Melbourne, Australia. AEP owns 100% of SEEBOARD and CitiPower. The revenues and operating expenses for SEEBOARD and CitiPower are included in worldwide revenues and expenses on AEP's Consolidated Statements of Income. Interest, taxes and other nonoperating items for SEEBOARD and CitiPower are included in the appropriate income statement lines.

In 1998 SEEBOARD's 80% owned subsidiary, SEEBOARD Powerlink, signed a 30-year contract for $1.6 billion to operate, maintain, finance and renew the high-voltage power distribution network of the London Underground transportation system. SEEBOARD Powerlink will be responsible for distributing high voltage electricity to supply 270 London Underground stations and 250 miles of the rail system's track. SEEBOARD's partners in Powerlink are an international electrical engineering group and an international cable and construction group.

AEP has a 50% investment in Yorkshire, another U.K. regional electricity distribution and supply company. The investment is accounted for using the equity method of accounting with equity earnings included in other income (net) on the AEP Consolidated Statements of Income. In December 2000 AEP entered into negotiations to sell its investment in Yorkshire. On February 26, 2001, an agreement to sell AEP's 50% interest in Yorkshire was signed. The sale is expected to close by March 31, 2001. See Note 10 of the Notes to Consolidated Financial Statements.

In the U.K. all residential and commercial customers have been allowed to choose their electricity supplier since May 1999. Margins on retail electric sales have been generally declining due to competition. In April 2000 final proposals from the regulatory commission reduced distribution rates and electricity supply price caps. The distribution rate reductions and reduced price caps are expected to reduce AEP's earnings from SEEBOARD and its Yorkshire investment. In response to these final proposals and increasing competition, SEEBOARD and Yorkshire adopted an aggressive program of reducing controllable costs. Significant features of this program include staff reductions, outsourcing of certain functions and consolidation of facilities. Management intends to aggressively pursue this cost reduction program and continues to evaluate additional cost reduction measures to further mitigate the effects of the final proposals and increasing competition in the U.K. electricity supply business. Management expects that, despite the cost control measures, the rate reductions will negatively impact AEP's earnings.

The Utilities Act which became law in the U.K. in July 2000 includes a requirement for separate licensing of electricity supply and distribution and the introduction of a prohibition of electricity supply and distribution licenses being held by the same legal entity. This requirement effectively means that the electricity supply and distribution businesses of SEEBOARD and Yorkshire must be held by separate companies. However, AEP will not be required to divest its interest in either the supply entity or the distribution entity. The separation of the supply and distribution business into two entities each for SEEBOARD and Yorkshire is not expected to have a material impact on future results of operations or cash flows.

Beginning January 1, 2001 price reductions on the supply and distribution of electricity are being implemented in Victoria, Australia. The effect of these price reductions is expected to reduce CitiPower's results of operations to the extent that they cannot be offset by reduced expenses, improved efficiencies or increased sales.

A new, higher tariff rate for the electricity from two 250 MW coal-fired generating units located in Henan Province, China was approved by the Central Chinese government in January 2000. AEP owns 70% of these units, with the remaining 30% owned by two Chinese partners. As a result of the new tariff the units contributed positively to

AEP's results of operations for 2000 after incurring a loss in 1999.

Other foreign generating facilities include a 37.5% interest in 675 MW of capacity in the U.K. and a 50% interest in 118 MW of capacity in Mexico. AEP also has a 50% ownership interest in two generating plants under construction; a 600 MW facility in Mexico and a 400 MW facility in the U.K. All of these facilities sell their capacity under long-term contracts. The investment in these facilities is accounted for using the equity method.

AEP, through its CSW Energy subsidiary, has an ownership interest in seven operational domestic generation facilities in Colorado, Florida and Texas with one 440 MW facility under construction. These plants are EWGs or qualifying facilities (QF) as defined by law and not subject to cost-based rate regulation or the application of SFAS 71 regulatory accounting. The combined installed capacity of the operational facilities is 1,508 MW at December 31, 2000. The power from these QF facilities is sold under long-term power purchase agreements with the local host facility. Any merchant power is sold in the wholesale market generally under short-term contract. As a result, increases in the market price of natural gas used to generate electricity at these facilities may adversely impact results of operations.

In 1999 a 50% equity interest in one of the above facilities was sold to an unaffiliated company. The after-tax gain from the sale was approximately $33 million. An additional unit is under construction at this facility. Pursuant to the terms of the sale agreement, the unaffiliated company will make additional payments to CSW Energy upon completion of the additional unit.

Under terms of the FERC and Texas settlement agreements that approved the merger, the divestiture of certain generating units is required. The Frontera power plant, one of CSW Energy's facilities, is specifically identified as one of the plants where the entire ownership interest must be sold. On February 8, 2001, AEP announced that it had reached agreement with an unaffiliated company to sell the 500 MW Frontera power plant for $265 million in cash.

In 2000 an electricity and gas trading operation in Europe was added. This business requires minimal capital investment and offers an opportunity to employ our expertise in energy marketing and trading to a new market.

The domestic gas trading operation grew substantially in 2000 and is expected to benefit from the planned acquisition of the Houston Pipe Line Company which was announced in January 2001. The acquisition of Houston Pipe Line Company, which has more than 4,400 miles of natural gas transmission pipeline and operates one of the largest storage facilities, is expected to complement our intra-state gas transmission and storage facilities in Louisiana and extends AEP's strategy of linking physical energy asset operations with trading and marketing operations.

AEP's Louisiana gas operation is LIG, a midstream natural gas operation, that was purchased in December 1998 for approximately $340 million including working capital funds. LIG includes a fully integrated natural gas gathering, processing, storage and transportation operation in Louisiana and a gas trading and marketing operation. Assets include an intrastate pipeline system, natural gas liquids processing plants and natural gas storage facilities.

AEP's subsidiaries are engaged in the engineering and construction for third parties of three power plants in the U.S. with a capacity of 1,910 MW. These plants will be natural gas-fired facilities that are scheduled to be completed from 2001 to 2003. AEP intends to use its engineering, trading and marketing expertise on these projects some of which also include power purchase and power sale agreements to enhance its results of operations.

**Other Matters – Affecting AEP, AEGCo, APCo, CPL, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo and WTU**

*New Accounting Standards* – SFAS 133, "Accounting for Derivative Instruments and Hedging Activities", as amended by SFAS 137 and SFAS 138, is effective for the AEP System beginning January 1, 2001. SFAS 133 requires that entities recognize all derivatives as either assets or liabilities and measure them at fair value. Changes in the fair value of derivative assets and liabilities must be recognized currently in net income. Changes in the derivatives that are effective cash flow hedges are recorded in other comprehensive income.

Pending the resolution of certain industry issues presently before the FASB's Derivatives Implementation Group (DIG), the effect of adoption of SFAS 133 will result in transition adjustment amounts which will have an immaterial effect on both net income and other comprehensive income.

The FASB's DIG, has issued tentative guidance, which has not yet been approved by the FASB, that option contracts cannot qualify as normal purchases and sales. In addition there are two industry issues pending resolution by the DIG related to whether electric capacity contracts that may have some characteristics of purchased and written options can qualify as normal sales, and whether contracts which do not result in physical delivery of power because of transmission constraints are derivatives.

While the Company believes the majority of the its fuel supply agreements should qualify as normal purchases and that the majority of its power sales agreements qualify as normal sales, the ultimate resolution of the above issues may result in accounting for certain power sales and fuel supply agreements as derivatives which may have a material effect on reported net income under SFAS 133. Whether the impact will be favorable or adverse will depend on the market prices compared to the contractual prices at the time of valuation.

ATTACHMENT 2 TO C0501-13

# INDIANA MICHIGAN POWER COMPANY
# PROJECTED CASH FLOW FOR THE YEAR 2001

**Indiana Michigan Power Co.**
**2001 Forecasted Internal Cash Flow**
**$ Millions**

| | 2001 |
|---|---|
| Net income After Taxes | 125.4 |
| Less: Dividends | 98.9 |
| | 26.5 |
| Adjustments: | |
| Depreciation and Amortization | 168.7 |
| Amortization of Deferred Operating Costs | 78.9 |
| Deferred Federal Income Taxes and Investment Tax Credits | (56.4) |
| AFUDC | (0.9) |
| Changes in Working Capital | (95.6) |
| Total Adjustments | 94.7 |
| **Internal Cash Flow** | 121.2 |
| Average Quarterly Cash Flow | 30.3 |
| Average Cash Balances and Short-Term Investments | 7.0 |
| Total | 37.3 |

Projected