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FITZPATRICK,E.E Indiana Michigan Power Co. (formerly Indiana & Michigan Ele
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See Financial Reports

SUBJECT: "Indiana Michigan Power Co's Annual Rept for 1997."
Projected cash flow for 1998,encl.W/980428 ltr.

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Indiana Michigan
Power Company
500 Circle Drive
Buchanan, MI 49107 1395

INDIANA MICHIGAN POWER

April 28, 1998

AEP:NRC:0909N

Docket Nos.: 50-315
50-316

U. S. Nuclear Regulatory Commission
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Washington, D.C. 20555-0001

Gentlemen:

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

Attachment 1 contains Indiana Michigan Power Company's annual report for 1997. Attachment 2 contains a copy of Indiana Michigan Power Company's projected cash flow for 1998. These reports are submitted pursuant to 10 CFR 50.71(b) and 10 CFR 140.21(e).

Sincerely,

S J Brewer for EEF

E. E. Fitzpatrick
Vice President

vlb

Attachments

cc: J. A. Abramson
A. B. Beach
MDEQ - DW & RPD
NRC Resident Inspector
J. R. Sampson

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ATTACHMENT 1 TO AEP:NRC:0909N

INDIANA MICHIGAN POWER COMPANY'S
ANNUAL REPORT FOR 1997

1997 Financial Statements and Management's Discussion and Analysis of Results of Operations and Financial Condition

AEP AMERICAN® ELECTRIC POWER

AEP: America's Energy Partner℠

AMERICAN ELECTRIC POWER
1 Riverside Plaza
Columbus, Ohio 43215-2373

CONTENTS

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
SELECTED CONSOLIDATED FINANCIAL DATA

Year Ended December 31,	1997	1996	1995	1994	1993
INCOME STATEMENTS DATA (in millions):					
Operating Revenues	$6,161	$5,849	$5,670	$5,505	$5,269
Operating Income	984	1,008	965	932	929
Income Before Extraordinary Item	620	587	530	500	354
Extraordinary Loss - UK Windfall Tax	109	-	-	-	-
Net Income	511	587	530	500	354

December 31,	1997	1996	1995	1994	1993
BALANCE SHEETS DATA (in millions):					
Electric Utility Plant	$19,597	$18,970	$18,496	$18,175	$17,712
Accumulated Depreciation and Amortization	7,964	7,550	7,111	6,827	6,612
Net Electric Utility Plant	$11,633	$11,420	$11,385	$11,348	$11,100
Total Assets	$16,615	$15,883	$15,900	$15,736	$15,359
Common Shareholders' Equity	4,677	4,545	4,340	4,229	4,151
Cumulative Preferred Stocks of Subsidiaries:					
Not Subject to Mandatory Redemption	47	90	148	233	268
Subject to Mandatory Redemption*	128	510	523	590	501
Long-term Debt*	5,424	4,884	5,057	4,980	4,995
Obligations Under Capital Leases*	538	414	405	400	284

*Including portion due within one year

Year Ended December 31,	1997	1996	1995	1994	1993
COMMON STOCK DATA:					
Earnings per Common Share:					
Before Extraordinary Item	$ 3.28	$3.14	$2.85	$2.71	$1.92
Extraordinary Loss - UK Windfall Tax	(0.58)	-	-	-	-
Net Income	$ 2.70	$3.14	$2.85	$2.71	$1.92
Average Number of Shares Outstanding (in thousands)	189,039	187,321	185,847	184,666	184,535
Market Price Range: High	$ 52	$44-3/4	$40-5/8	$37-3/8	$40-3/8
Low	39-1/8	38-5/8	31-1/4	27-1/4	32
Year-end Market Price	51-5/8	41-1/8	40-1/2	32-7/8	37-1/8
Cash Dividends Paid	$2.40	$2.40	$2.40	$2.40	$2.40
Dividend Payout Ratio	88.7%(a)	76.5%	84.1%	88.6%	125.2%
Book Value per Share	$24.62	$24.15	$23.25	$22.83	$22.50

(a) Dividend Payout Ratio before Extraordinary Loss - UK Windfall Tax is 73.1%.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS AND FINANCIAL CONDITION

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 that could cause actual results to differ materially are: electric load and customer growth; abnormal weather conditions; available sources and costs of fuels and availability of generating capacity; the speed and degree to which competition is introduced to our power generation business, the terms of the transition to competition, and its impact on rate structures; the ability to recover stranded costs, new legislation and government regulations, the ability of the Company to successfully reduce its costs including synergy estimates; the degree to which the Company develops non-regulated business ventures and their success; the economic climate and growth in our service territory; inflationary trends, interest rates and other risks.

In 1997 management took several major steps towards our growth oriented goal of being America's Energy Partner and a global energy and related services company. Construction of a 250-megawatt generating station in China, jointly owned with two Chinese partners, progressed on schedule and within budget. In April, the Company and New Century Energies, Inc. acquired Yorkshire Electric Group plc, a United Kingdom (UK) distribution company. The Yorkshire investment is accounted for using the equity method. A new power marketing business was launched in July contributing significantly to our operating revenues which surpassed $6 billion for the first time. A joint venture with Conoco, an energy subsidiary of DuPont, was announced in October that will provide energy management services as well as financing of steam and electric generation facilities at large commercial and industrial plant sites including initially 16 Conoco and Dupont plant sites. The completion of agreements for the joint venture companies and the commencement of operations are expected in 1998.

In December 1997 American Electric Power Company (AEP or the Company) and Central and South West Corporation (CSW) agreed to merge. The merger is subject to approval by regulators and shareholders. Completion of the merger is expected to occur in the first half of 1999. CSW, a Dallas-based public utility holding company, owns four domestic electric utility subsidiaries serving 1.7 million customers in portions of Texas, Oklahoma, Louisiana and Arkansas and a regional electricity company in the UK. Other international energy operations and non-utility subsidiaries owned by CSW are involved in energy-related investments, telecommunications, energy efficiency services and financial transactions.

Income Before Extraordinary Loss Increases

AEP's 1997 income before an extraordinary loss, the one-time UK Windfall Tax, increased 6% to $620 million or $3.28 per share from $587 million or $3.14 per share in 1996. The increase was primarily attributable to increased transmission service revenues, reduced preferred stock dividends due to a redemption program and an increase in nonoperating income from the April 1997 investment in Yorkshire exclusive of the extraordinary loss. Net income inclusive of the $109 million extraordinary loss decreased $76 million or 13% primarily due to the UK one-time windfall tax which was based on a revision or recomputation of the original privatization value of certain privatized utilities, including Yorkshire.

For further details regarding changes in operating revenues and expenses, taxes and nonoperating investment earnings in 1997 and 1996 see Results of Operations.

Business Outlook

The Company's ability to recover its costs as the industry transitions to competition and as customer choice is more broadly available is the most significant factor affecting its future. Competition in the wholesale generation market continues to intensify since the adoption of federal legislation in 1992 which gave wholesale customers the right to choose their energy supplier and the Federal Energy Regulatory Commission (FERC) orders issued in 1996 which forced open access transmission. The introduction of competition and customer choice for retail customers has been slow although activity has been increasing. Federal legislation has been proposed to mandate competition and customer choice at the retail level, and several states have introduced or are considering similar legislation. All of our states have initiatives to move to customer choice that will phase-in or allow for a transition to competition, although the timing is uncertain. The Company supports customer choice and is proactively involved in discussions at both the state and federal levels regarding how best to structure and transition to a competitive marketplace.

As the cost of generation in the electric energy market evolves from cost-of-service ratemaking to market-based pricing, many complex issues must be resolved, including the recovery of stranded costs. While FERC orders No. 888 and 889 provide, under certain conditions, for recovery of stranded cost at the wholesale level, the issue of stranded cost is unresolved at the much larger retail level. The amount of any stranded costs we may experience depends on the timing and extent to which direct competition is introduced to our business and the then-existing market price of electricity.

Under the provisions of Statement of Financial Accounting Standards (SFAS) No. 71 "Accounting for the Effects of Certain Types of Regulation," regulatory assets (deferred expenses) and regulatory liabilities (deferred revenues) are included in the consolidated balance sheets of regulated utilities in accordance with regulatory actions and in order to match expenses and revenues with cost-based rates. In order to maintain net regulatory assets (net expense deferrals) on the balance sheet, SFAS No. 71 requires that rates charged to customers be cost-based. In the event a portion of AEP's business no longer meets the requirements of SFAS No. 71, net regulatory assets would have to be written off for that portion of the business. The provisions of SFAS No. 71 and SFAS No. 101 "Accounting for the Discontinuance of Application of Statement No. 71" never anticipated that deregulation would include an extended transition period or that it would provide for recovery of stranded costs after the transition period. In July 1997 the Emerging Issues Task Force (EITF) of the Financial Accounting Standards Board (FASB) reached a consensus that the application of SFAS No. 71 to a segment of a regulated electric utility which is subject to a legislative plan to transition to competition in that segment should cease when the legislation is passed or an enabling rate order is issued containing sufficient detail for the utility to reasonably determine what the plan would entail. The EITF indicated that the cessation of application of SFAS 71 would require that regulatory assets and impaired plant be written off unless they are recoverable.

Although FERC orders No. 888 and 889 provide for competition in the firm wholesale market, that market is a relatively small part of our business and most of our firm wholesale sales are still under cost-of-service contracts. As a result AEP's generation business is still cost-based

regulated and should remain so for the near future pending the passage of enabling state legislation to deregulate the generation business. We believe that enabling state legislation should provide for the recovery of any generation-related net regulatory assets and other reasonable stranded costs from impaired generation assets. We are working with regulators, customers and legislators to provide for recovery of these stranded costs during a transition period in which rates are fixed or frozen and electric utilities would take steps to achieve cost savings which would be used to reduce or eliminate their stranded costs. However, if in the future AEP's generation business 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.

Cost Containment and Process Improvements

Efforts continue by AEP to reduce the costs of its products and services in order to maintain our competitiveness. Prior to 1997, reviews of our major domestic processes led to decisions to consolidate management and certain functions and operations and improve certain major processes. While staff reductions and cost savings resulting from the restructuring and improvements are presently being achieved, expenses for new marketing, customer services and modern efficient management information systems are increasing to prepare for competition. In 1997 the costs of these efforts to prepare for competition offset the savings from restructuring.

In 1997, AEP also began installing a new unified customer service system which is designed to support the request for service, billings, accounts receivable, credit and collection functions. AEP's new unified customer service system replaces a 30-year-old customer system and a nine-year-old transmission and distribution work management system. Process improvement efforts and expenditures to develop and implement the new customer service system and similar efforts and expenditures to acquire, install and enhance new client server-based accounting and budgeting/financial planning software should produce further improvements and efficiencies, enabling AEP to continue to offer its customers excellent service at competitive prices.

Fuel Costs

AEP recognizes that it must continue to manage coal costs to maintain its competitive position. Approximately 90% of AEP's generation is coal fired and approximately 17% of the 53 million tons of coal burned in 1997 were supplied by affiliated mines with the remainder acquired under long-term contracts and purchases in the spot market. As long-term contracts expire we are negotiating with unaffiliated suppliers to lower coal costs. We intend to continue to prudently supplement our long-term coal supplies with spot market purchases as long as favorable spot market prices exist.

In prior years we have agreed in our Ohio jurisdiction to certain limitations on the recovery of affiliated coal costs. Our analysis shows that we should be able to recover the Ohio jurisdictional portion of the costs of our affiliated mining operations including future mine closure costs. Management intends to seek recovery of its non-Ohio jurisdictional portion of the investment in and the liabilities and closing costs of our affiliated mines estimated at $102 million after tax. However, should it become apparent that these affiliated mining costs will not be recovered from Ohio and/or non-Ohio jurisdictional customers, the mines may have to be closed and future earnings, cash flows and possibly financial condition could be adversely affected. In addition

compliance with Phase II requirements of the Clean Air Act Amendments of 1990 (CAAA), which become effective in January 2000, could also cause the mining operations to close. Unless the cost of any mine closure is recovered either in regulated rates or as a stranded cost under a plan to transition the generation business to competition, future earnings, cash flows and possibly financial condition could be adversely affected.

Nuclear Costs

Significant efforts have been made to enhance our competitiveness in nuclear power generation and to improve our nuclear organizational efficiency. In 1997 we continued to receive the "excellence in performance" award from the Institute of Nuclear Power Operations. Nuclear power plants have a major future financial commitment to safely dispose of spent nuclear fuel (SNF) and radioactive plant components (i.e. to decommission the plant). It is difficult to reduce nuclear generation costs since certain major cost components are impacted by federal laws and Nuclear Regulatory Commission (NRC) regulations.

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 we participate in the Department of Energy (DOE) SNF disposal program which is described in Note 4 of the Notes to Consolidated Financial Statements. Since 1983 our customers have paid $272 million for the disposal of nuclear fuel consumed at the Donald C. Cook Nuclear Plant (Cook Plant). Under the provisions of the Nuclear Waste Policy Act, collections from customers are to provide the DOE with money to build a repository for spent fuel. To date the federal government has not made sufficient progress towards a permanent repository or otherwise assuming responsibility for SNF. As long as there is a delay in the construction of a government approved storage repository for SNF, the cost of both temporary and permanent storage will continue to increase. The cost to decommission the Cook Plant is affected by both NRC regulations and the DOE's SNF disposal program. Studies completed in 1997 estimate the cost to decommission the Cook Plant range from $700 million to $1.152 billion in 1997 dollars. This estimate could escalate due to uncertainty in the DOE's SNF disposal program and the length of time that SNF may need to be stored at the plant site delaying decommissioning. Presently we are recovering the estimated cost of decommissioning the Cook Plant over its remaining life. However, AEP's future results of operations, cash flows and possibly its financial condition could be adversely affected if the cost of SNF disposal and decommissioning continues to increase and cannot be recovered.

On September 9 and 10, 1997, during a NRC architect engineer design inspection, questions regarding the operability of certain safety systems caused Company operations personnel to shut down Units 1 and 2 of the Cook Plant. On September 19, 1997, the NRC issued a Confirmatory Action Letter requiring the Company to address the issues identified in the letter. The Company is working with the NRC to resolve these issues and other issues related to restart of the units. Certain issued identified in the letter have been addressed. At this time management is unable to determine when the units will be returned to service. If the units are not returned to service in a reasonable period of time, it could have an adverse impact on results of operations, cash flows and possibly financial condition.

Environmental Concerns

We take great pride in our efforts to economically produce and deliver electricity while minimizing the impact on the environment. Over the years AEP has spent over a billion dollars to equip our facilities

with the latest cost effective clean air and water technologies and to research possible new technologies. We are also proud of our award winning efforts to reclaim our mining properties. We intend to continue in a leadership role fostering economically prudent efforts to protect and preserve the environment.

Hazardous Material

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, our generating plants and transmission and distribution facilities have used asbestos, polychlorinated biphenyls (PCB) and other hazardous and nonhazardous materials. We are currently incurring costs to safely dispose of such substances. Additional costs could be incurred to comply with new laws and regulations if enacted.

The Comprehensive Enviromental Response, Compensation and Liability Act (CERCLA or Superfund) addresses clean-up of hazardous substances at disposal sites and authorized the United States Environmental Protection Agency (Federal EPA) to administer the clean-up programs. As of year-end 1997, we are involved in litigation with respect to five sites overseen by the Federal EPA and have been named by the Federal EPA as a "Potentially Responsible Party" (PRP) for seven other sites. There are seven additional sites for which AEP companies have received information requests which could lead to PRP designation. Also, an AEP subsidiary has received an information request with respect to one site administered by state authorities. Our liability has been resolved for a number of sites with no significant effect on results of operations. In those instances where we have been named a PRP or defendant, our disposal or recycling activity was in accordance with the then-applicable laws and regulations. Unfortunately, CERCLA 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 our potential future liability. Disposal at a particular site by AEP is often unsubstantiated; the quantity of material we disposed of at a site was generally small; and the nature of the material we generally disposed of was nonhazardous. Typically, we are one of many parties named as PRPs for a site and, although liability is joint and several, generally some of the other parties are financially sound enterprises. Therefore, our present estimates do not anticipate material cleanup costs for identified sites for which we have been declared PRPs. However, if for reasons not currently identified significant cleanup costs are attributed to AEP in the future, results of operations, cash flows and possibly financial condition would be adversely affected unless the costs can be recovered from customers.

Federal EPA Actions

Federal EPA is required by the CAAA to issue rules to implement the law. In December 1996 Federal EPA issued final rules governing nitrogen oxide (NOx) emissions that must be met after January 1, 2000 (Phase II of the CAAA). The final rules will require substantial reductions in NOx emissions from certain types of boilers including those in AEP's power plants. On February 13, 1998, the United States Court of Appeals for the District of Columbia Circuit, in an appeal in which the AEP System operating companies participated, upheld the emission limitations. In addition in November 1997 the Federal EPA

published a proposed rulemaking requiring the revision of state implementation plans in 22 eastern states, including those states in which the operating companies of the AEP System have coal-fired generating plants. The proposed rule will require reductions in NOx emissions from utility sources of approximately 85% below 1990 levels and entail very substantial capital and operating expenditures by AEP System operating companies. Pollution controls to meet the proposed revised NOx emission limits would have to be in place by 2002. Eight northeast states have petitioned Federal EPA for the imposition of additional NOx controls for upwind industrial and utility sources. The matter is being litigated. The costs to comply with the emission reductions required by the Federal EPA's actions are expected to be substantial and would have a material adverse impact on future results of operations, cash flows and possibly financial condition if the resultant costs are not recovered from customers.

In 1997 the Federal EPA published a revised ambient air quality standard for ozone and established a new ambient air quality standard for fine particulate matter. These standards are expected to result in redesignation of a number of areas of the country currently in compliance with the existing standard to nonattainment status which could ultimately dictate more stringent emission restrictions for AEP generating units. Under the new rules the states must first determine whether the standards are being achieved. The states then have three years to submit a compliance plan and up to ten years after designation to come into compliance with the new standards. The compliance deadline could be as late as 2010 for the ozone standard and 2012-2015 for the fine particulate standard. Although we are reviewing the impact of the new rules, we are unable to estimate compliance costs without knowledge of the reductions that will be necessary to meet the new standards. If such reductions are significant and the Company must bear a significant portion of the cost of compliance in a region that is in violation of the revised standards, it would have a material adverse effect on results of operations, cash flows and possibly financial condition unless such costs are recovered from customers.

At the global climate conference in Kyoto, Japan in December 1997 more than 160 countries, including the United States, negotiated a treaty limiting emissions of greenhouse gases, chiefly carbon dioxide, which may eventually contribute to global warming. Although there is no clear scientific evidence that carbon dioxide contributes to global warming and damages the environment, the treaty, which requires Congressional approval, calls for a seven percent reduction below the emission levels of greenhouse gases in 1990. We intend to work with Congress to insure that science and reason are introduced to the debate. If approved by Congress the costs to comply with the emission reductions required by the Kyoto treaty is 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.

Results of Operations

Net Income Declines Due to Extraordinary Loss

Net income decreased 13% to $511 million primarily due to an extraordinary loss of $109 million from the UK's one-time windfall tax which was based on a retroactive revaluation of the original privatization price of certain privatized utilities, including Yorkshire. Income before the extraordinary loss increased 6% in 1997 to $620 million or $3.28 per share from $587 million or $3.14 per share in 1996. The increase is primarily attributable to increased transmission service sales, reduced preferred stock dividends due to a redemption program and an increase in

nonoperating income from the April 1997 investment in Yorkshire exclusive of the extraordinary loss.

In 1996 net income increased 11% to $587 million or $3.14 per share from $530 million or $2.85 per share in 1995. The increase was mainly attributable to increased sales of energy and services and reduced interest charges and preferred stock dividends. Sales increased due to increased transmission and other services provided to power marketers and utilities and increased energy sales to non-affiliated utilities and industrial customers. The reduction in interest and preferred stock dividends resulted from the Company's refinancing program. Also contributing to the improvement in net income in 1996 were severance pay charges recorded in 1995 in connection with the restructuring of management and operations and gains recorded in 1996 from emission allowance transactions.

Revenues and Sales Increase

Operating revenues increased 5% in 1997 and 3% in 1996. Increased wholesale energy sales and transmission and coal conversion service revenues were the primary reasons for the increases in both years. The change in revenues can be analyzed as follows:

	Increase (Decrease) From Previous Year			
(Dollars in Millions)	1997		1996	
	Amount	%	Amount	%
Retail:				
Price Variance	$(44.0)		$ (42.9)	
Volume Variance	2.4		63.7	
Fuel Cost Recoveries	27.3		15.0	
	(14.3)	(0.3)	35.8	0.7
Wholesale:				
Price Variance	9.6		(202.0)	
Volume Variance	269.7		317.3	
Fuel Cost Recoveries	8.3		(3.6)	
	287.6	36.3	111.7	16.4
Other Operating Revenues	38.8		31.4	
Total	$312.1	5.3	$ 178.9	3.2

The slight decrease in retail revenues in 1997 was largely due to a decline in higher priced sales to weather-sensitive residential customers reflecting mild weather. The decline in residential sales was completely offset by an increase in lower priced sales to industrial customers, reflecting increased usage which resulted in a small increase in total retail energy sales. The negative price variance resulted from the shift from higher priced residential sales to lower priced industrial sales.

In 1997 wholesale revenues and sales increased significantly primarily due to new power marketing transactions which began in July 1997 when AEP commenced a power marketing business. The new power marketing transactions involve the substantial purchase and sale of electricity outside of the AEP transmission system. An increase in coal conversion service sales also contributed to the significant increase in wholesale sales and revenues. These sales are for the generation of electricity from the coal of the purchaser.

An increase of $33 million in transmission service revenues produced the increase in other operating revenues in 1997. Transmission service revenues are for the transmission of other companies' power through AEP's extensive transmission system. These revenues have increased significantly since the issuance of the FERC's open access transmission rules in 1996.

In 1996 retail revenues increased slightly due to growth in the number of customers and the addition of a major new industrial customer in December 1995. Revenues from higher priced sales to residential customers, the most weather-sensitive customer class, were flat, increasing less than one percent, as the effect of cold winter weather in early 1996 was offset by mild summer and December temperatures. Revenues from lower priced commercial and industrial customers increased 1% reflecting growth in the number of customers. The increase in lower priced

commercial and industrial sales accounted for the negative price variance in 1996.

Wholesale revenues increased 16% in 1996 reflecting a 46% increase in wholesale sales attributable largely to transactions with power marketers and other utilities. During 1996 the Company began providing coal conversion services resulting in 6.8 billion kilowatthours of electricity generated for power marketers and certain other utilities from their coal under a new FERC-approved interruptible, contingent sales tariff. These sales have lower prices because there is no associated fuel cost. As a result the average price per kilowatthour was significantly less in 1996 than in 1995 producing a negative price variance. Also contributing to the increased wholesale sales was a long-term contract with an unaffiliated utility to supply 205 MW of energy for 15 years beginning January 1, 1996.

An increased level of activity in the wholesale energy markets, due to FERC's open access rulemaking and AEP's aggressive efforts to provide flexible and competitively priced transmission services led to an increase in transmission service revenues in 1996. As a result transmission service revenues, which are recorded in other operating revenues, increased by approximately $24 million.

The level of wholesale sales tends to fluctuate due to the highly competitive nature of the short-term energy market and other factors, such as affiliated and unaffiliated generating plant availability, the weather and the economy. The FERC rules which introduce a greater degree of competition into the wholesale energy market have had the effect of increasing short-term wholesale sales and transmission service revenues. The Company's sales and in turn its results of operations were impacted in 1997 and 1996 by the quantities of energy and services sold to wholesale customers. Future results of operations will be affected by the quantity and price of wholesale transactions which often depend on the level of competition, the weather and power plant availability, both affiliated and non-affiliated, factors the Company does not control. However, we work to take advantage of these factors when they are favorable.

Operating Expenses Increase

Operating expenses increased 7% in 1997 and 3% in 1996. Increased purchased power expense, mainly from the Company's new power marketing business, was the primary reason for the 1997 increase. New marketing, customer services and software costs to prepare for competition also contributed to the increase. The primary items accounting for the increase in 1996 were increased fuel costs, federal income taxes and expenditures for marketing, information systems and other items necessary to prepare for the transition to competition. Changes in the components of operating expenses were as follows:

(Dollars in Millions)	Increase (Decrease) From Previous Year			
	1997		1996	
	Amount	%	Amount	%
Fuel	$ 26.4	1.6	$ 63.5	4.1
Purchased Power	330.2	383.5	(2.3)	(2.6)
Other Operation	17.3	1.4	25.9	2.2
Maintenance	(19.6)	(3.9)	(39.0)	(7.2)
Depreciation and Amortization	(9.7)	(1.6)	7.8	1.3
Taxes Other Than Federal Income Taxes	(8.0)	(1.6)	9.4	1.9
Federal Income Taxes	(0.9)	(0.3)	70.2	25.8
Total	$335.7	6.9	$135.5	2.9

Fuel expense increased in 1997 primarily due to an increase in the average cost of fuel consumed reflecting the reduced availability of lower cost nuclear generation in 1997 due to the unplanned shutdown and maintenance outage of both nuclear units which began on September 10 and continued through year-end. The increase in fuel expense in 1996 was primarily due to an increase in generation to meet the increase in industrial and wholesale customer demand. The effect of increased generation was partially offset by reduced average fossil

fuel costs, resulting from increased usage of lower cost spot market coal, and lower cost nuclear fuel.

The significant increase in purchased power expense in 1997 was primarily due to purchases of electricity for the new power marketing business. These purchases were made to cover sales made to non-affiliates by the new power marketers.

In 1997 restructuring savings in other operation expense were more than offset by additional expenses for marketing, customer service and software costs to prepare for the service demands of competition.

Maintenance expense decreased in 1996 due to the deferral of previously expensed storm damage costs commensurate with their recovery over 5-years and reduced nuclear plant maintenance expense due to workforce reductions and the reduction of contract labor at the Cook Plant.

The increase in federal income tax expense attributable to operations in 1996 was primarily due to an increase in pre-tax operating income and changes in certain book/tax differences accounted for on a flow-through basis and certain permanent differences.

Nonoperating Income

The increase in nonoperating income in 1997 was mainly due to income from non-regulated operations. The Company's share of earnings from its April 1997 investment in Yorkshire was $34 million which includes $10 million of nonrecurring tax benefits related to a reduction of the UK corporate income tax rate from 33% to 31% effective April 1,1997. The utilization of foreign tax credits also contributed to the increase in nonoperating income. Nonoperating income decreased in 1996 due to the cost of the AEP branding program and the cost of efforts to develop and make investment in new non-regulated business ventures.

Interest Charges and Preferred Stock Dividend Requirements

In 1997 interest charges on both long-term and short-term debt increased reflecting additional borrowing primarily to fund the Company's non-regulated operations including the investment in Yorkshire. Preferred stock dividend requirements of the subsidiaries decreased in 1997 due to the reacquisition of over 4 million shares of cumulative preferred stock.

The decrease in interest charges and preferred stock dividend requirements in 1996 was mainly due to continued refinancing programs of the Company's subsidiaries. The refinancings reduced the average interest rate and the amount of long-term debt and preferred stock outstanding. The cost of short-term borrowings in 1996 increased slightly reflecting an increased average balance of short-term debt outstanding.

Financial Condition

In 1997 AEP maintained its strong financial condition and performance in shareholder value. The year-end closing stock price of $51-5/8 was 25.5% higher than the prior year and 57% greater than the 1994 closing price. The Company paid a quarterly dividend in 1997 of 60 cents a share maintaining the annual dividend rate at $2.40 per share. The 1997 payout ratio before extraordinary loss at 73% was 3% better than 1996's and 15% better than 1994's. It has been a management objective to reduce the payout ratio through efforts to increase earnings in order to enhance AEP's ability to invest in new business ventures that can complement our core competencies and improve shareholder value. AEP's three-year total shareholder return ranked fourth among the companies in the S&P Electric

Utility Index. This marked the fourth straight year in the top quartile of the Index. Management's goal is to maintain our position in the top quartile of the S&P Electric Utility Index for three-year total shareholder return.

Capital Investments

The total consideration paid in 1997 by a joint venture of AEP and an unaffiliated company to acquire Yorkshire was approximately $2.4 billion which was financed by a combination of equity and non-recourse debt. AEP initially funded its 50% equity investment in the joint venture with $50 million in cash, a $300 million adjustable rate term loan under a long-term revolving credit agreement and $10 million of short-term debt. For more information see Note 7 of the Notes to Consolidated Financial Statements. Also the Company's 70% interest in the construction of two 125 MW units in China will require approximately $110 million of investment.

AEP's construction expenditures are expected to be $2.4 billion over the next three years which includes the Cook Plant's Unit 1 steam generator replacement, the China project and the cost of transmission and distribution projects for the improvement of and addition to electric energy delivery facilities. Approximately 90% of domestic construction expenditures, estimated to be $2.3 billion for the next three years, will be financed with internally generated funds.

Capital Resources - Structure and Liquidity

AEP achieved a year-end ratio of common equity to total capitalization including amounts due within one year of 45.5% for 1997, compared with 45.3% for 1996 and 43.1% for 1995. The Company's goal is to maintain the common equity ratio at a level of at least 40 percent. During 1997 the Company and its subsidiaries continued redefining and improving their debt to equity position. The Company's regulated subsidiaries redeemed 4,258,947 shares of cumulative preferred stock with rates ranging from 4.08% to 7.875% at a total cost of $433 million. The subsidiaries used short-term debt and junior subordinated deferrable interest debentures to pay for the preferred stock tendered and to benefit from the tax deductibility of interest.

The Company and its subsidiaries issued $882 million principal amount of long-term obligations in 1997 at interest rates ranging from 5.9% to 8.0%. The companies continued to reduce financing costs by retiring higher-cost bonds and restructuring the long-term debt from senior secured/first mortgage bonds to senior unsecured debt and junior debentures. The principal amount of long-term debt retirements, including maturities, totaled $343 million with interest rates ranging from 6.5% to 9.35%. Our operating subsidiaries senior secured debt/first mortgage bond ratings, which were reaffirmed and improved in 1997, are listed in the following table:

Company	Moody's	S&P	Fitch	D & P
Appalachian Power Co.	A3	A	A	A
Columbus Southern Power Co.	A3	A-	A-	A
Indiana & Michigan Power Co.	Baa1	A-	BBB+	N/A
Kentucky Power Co.	Baa1	A	BBB+	N/A
Ohio Power Co.	A3	A-	A-	A

N/A = Not applicable

The operating 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 companies formed to pursue non-regulated business opportunities are using short-term debt. Short-term debt increased $235 million from the prior year-end balance and decreased by $45 million in 1996. At December 31, 1997, AEP Co., Inc. (the parent company) and its subsidiaries had unused short-term lines of credit of $442 million, and several of AEP's subsidiaries

engaged in non-regulated investments and energy businesses had available $330 million under a $600 million revolving credit agreement which expires in 1999. The sources of funds available to AEP are dividends from its subsidiaries, short-term and long-term borrowings and, when necessary, proceeds from the issuance of common stock. AEP issued 1,755,000 shares in 1997, 1,600,000 shares in 1996 and 1,400,000 shares in 1995 of common stock through a Dividend Reinvestment Program and the Employee Savings Plan raising $77 million, $65 million and $49 million, respectively.

The following debt and preferred stock coverages of the principal operating subsidiaries remained strong in 1997:

	Coverages at December 31, 1997	
	Mortgage	Preferred Stock
Appalachian Power Co.	3.72	1.92
Columbus Southern Power Co.	4.95	N/A
Indiana & Michigan Power Co.	7.57	2.88
Kentucky Power Co.	4.23	N/A
Ohio Power Co.	9.74	3.67

N/A = Not Applicable

Unless the subsidiaries meet certain earnings or coverage tests, they cannot issue additional mortgage bonds or preferred stock. In order to issue mortgage bonds (without refunding existing debt), each subsidiary must have pre-tax earnings equal to at least two times the annual interest charges on mortgage bonds after giving effect to the issuance of the new debt. Generally, issuance of additional preferred stock requires after-tax gross income at least equal to one and one-half times annual interest and preferred stock dividend requirements after giving effect to the issuance of the new preferred stock. As the above chart indicates, the subsidiaries presently exceed these minimum coverage requirements.

Merger

In December 1997 AEP and CSW announced that their boards of directors approved a definitive merger agreement for a tax-free, stock-for-stock business combination transaction which if consummated would bring AEP's total market capitalization to approximately $28 billion. The combination is expected to be accounted for as a pooling of interests. Under the agreement, each common share of CSW will be converted to 0.6 shares of AEP. Based on the number of CSW common shares outstanding at December 31, 1997, AEP will issue approximately 127 million shares to CSW common stockholders (valued at $6.6 billion based on the closing price on the last trading day prior to the announcement of the merger). Under the merger agreement, there will be no changes with respect to the public debt issues or the outstanding preferred stock of AEP, CSW or their subsidiaries. The merger is conditioned, among other things, upon the approval of each company's shareholders and certain state and federal regulatory agencies. The companies anticipate that the required regulatory approvals can be obtained in 12 to 18 months. AEP is requesting regulatory and shareholder approval to increase the number of authorized shares from 300,000,000 to 600,000,000 in connection with the merger.

Market Risks

The Company as a major power producer and a trader of electricity and gas has certain financial market risks inherent in its routine business activities. The trading of electricity and gas and related future contracts exposes the Company to commodity price fluctuations. Market risk represents the risk of loss that may impact

the Company's consolidated financial position, results of operations or cash flows due to adverse changes in market prices and rates. As trading activity increases and the market for power evolves this risk will become much greater. Various policies and procedures have been established to manage market risks exposures including the limited usage of energy related derivatives. In its regular business activities, certain trading positions of the Company for electric and gas creates exposure to price volatility for those products. These commodities are subject to unpredictable price fluctuations due to changing economic and weather conditions. During 1997 the Company initiated a power and gas marketing operation that manages the Company's exposure to future price movements using forwards, futures and options. At December 31, 1997, the exposure for financial derivatives in these marketing activities were not material to the Company's consolidated results of operations, financial position or cash flows.

Investment in two foreign currency denominated joint ventures also exposes the Company to currency translation rate risk. At December 31, 1997, the Company's exposure to changes in foreign currency exchange rates related to projects in the UK and China is not material to its consolidated financial position, results of operations or cash flows. The Company does not presently utilize derivatives to manage its exposures to foreign currency exchange rate movements.

The Company is exposed to changes in interest rates primarily due to short- and long-term borrowings to fund its business operations. The debt portfolio has both fixed and variable interest rates, terms from one day to thirty years and an average duration of eight years at December 31, 1997.

The Company measures interest rate market risk exposure utilizing a Value at Risk (VaR) model. The model is based on the Monte Carlo method of simulated price movements with a 95% confidence level and a one year holding period. The volatilities and correlations were based on three years of monthly prices. The risk of potential loss in fair value attributable to the Company's exposure to interest rates, primarily related to long-term debt with fixed interest rates, was $501 million at December 31, 1997. A near term change in interest rates would not materially affect the consolidated financial position or results of operations of the Company. The Company is not currently utilizing derivatives to manage its exposure to interest rate fluctuations.

The Company has investments in debt and equity securities which are held in trust funds to decommission its nuclear plant. Approximately 85% of the trust fund value is invested in tax exempt and taxable bonds, short-term debt instruments or cash. The trust investments and their fair value are discussed in Note 9 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 trust fund and ultimate liability are recoverable from ratepayers.

Inflation affects AEP's cost of replacing utility plant and the cost of operating and maintaining its plant. The rate-making process limits our 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.

Other Matters

Corporate Owned Life Insurance

In connection with the audit of AEP's consolidated federal income tax returns the United States Internal Revenue Service (IRS) agents sought a ruling from the IRS National Office that certain interest deductions relating to a corporate owned life insurance (COLI) program should not be allowed. The Company established the COLI program in 1990 as a part of its strategy to fund and reduce the cost of medical benefits for retired employees. AEP filed a brief with the IRS National Office refuting the agents' position. No adjustments have been proposed by the IRS. However, should a full disallowance of COLI interest deductions be proposed it would, if sustained, reduce earnings by approximately $286 million (including interest). AEP believes it has meritorious defenses and will vigorously contest any proposed adjustments. No provisions for this amount have been recorded. In the event the Company is unsuccessful it could have a material adverse impact on results of operations and cash flows.

Computer Software - Year 2000 Compliance

Many existing computer hardware and software programs will not properly recognize calendar dates beginning in the year 2000. Unless corrected, this "Year 2000" problem may cause computer malfunctions, such as system shutdowns or incorrect calculations and system output. The Company is addressing the problem internally by modifying or replacing its computer hardware and software programs to mitigate its risk, minimize technical failures, and repair such failures if they occur. The problem is also being addressed externally with entities that interact electronically with the Company, including but not limited to, suppliers, service providers, government agencies, customers, creditors and financial service organizations. However, due to the complexity of the problem and the interdependent nature of computer systems, if the Company's corrective actions, and/or the actions of other interdependent entities, fail for critical applications, the Company may be adversely impacted in the year 2000. Although significant, the cost of correcting the "Year 2000" problem is not expected to have a material impact on results of operations, cash flows or financial condition.

New Accounting Standards

In June 1997 the FASB issued SFAS No. 130 "Reporting Comprehensive Income" and SFAS No. 131 "Disclosures About Segments of an Enterprise and Related Information." SFAS No. 130 establishes the standards for reporting and displaying components of "comprehensive income," which is the total of net income and all other changes in equity except those resulting from investments by shareholders and dispositions to shareholders. SFAS No. 131 initiates standards for reporting information about operating segments in annual and interim financial statements as well as related disclosures about products and services, geographic areas and major customers. AEP's adoption of these new reporting standards in 1998 is not expected to have a material adverse effect on the results of operations, cash flows and/or financial condition.

Litigation

AEP is involved in a number of legal proceedings and claims. While we are 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 and/or financial condition.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF INCOME

(in thousands - except per share amounts)

	Year Ended December 31,		
	1997	1996	1995
OPERATING REVENUES	$6,161,368	$5,849,234	$5,670,330
OPERATING EXPENSES:			
Fuel	1,627,066	1,600,659	1,537,135
Purchased Power	416,266	86,095	88,396
Other Operation	1,227,368	1,210,027	1,184,158
Maintenance	483,268	502,841	541,825
Depreciation and Amortization	591,071	600,851	593,019
Taxes Other Than Federal Income Taxes	490,595	498,567	489,223
Federal Income Taxes	341,280	342,222	272,027
TOTAL OPERATING EXPENSES	5,176,914	4,841,262	4,705,783
OPERATING INCOME	984,454	1,007,972	964,547
NONOPERATING INCOME (net)	59,572	2,212	20,204
INCOME BEFORE INTEREST CHARGES AND PREFERRED DIVIDENDS	1,044,026	1,010,184	984,751
INTEREST CHARGES	405,815	381,328	400,077
PREFERRED STOCK DIVIDEND REQUIREMENTS OF SUBSIDIARIES	17,831	41,426	54,771
INCOME BEFORE EXTRAORDINARY ITEM	620,380	587,430	529,903
EXTRAORDINARY LOSS - UK WINDFALL TAX	(109,419)	-	-
NET INCOME	$ 510,961	$ 587,430	$ 529,903
AVERAGE NUMBER OF SHARES OUTSTANDING	189,039	187,321	185,847
EARNINGS PER SHARE:			
Before Extraordinary Item	$3.28	$3.14	$2.85
Extraordinary Loss	(0.58)	-	-
Net Income	$2.70	$3.14	$2.85
CASH DIVIDENDS PAID PER SHARE	$2.40	$2.40	$2.40

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

(in thousands)

	Year Ended December 31,		
	1997	1996	1995
RETAINED EARNINGS JANUARY 1	$1,547,746	$1,409,645	$1,325,581
NET INCOME	510,961	587,430	529,903
DEDUCTIONS:			
Cash Dividends Declared	453,453	449,353	445,831
Other	237	(24)	8
RETAINED EARNINGS DECEMBER 31	$1,605,017	$1,547,746	$1,409,645

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Year Ended December 31,		
	1997	1996	1995
OPERATING ACTIVITIES:			
Net Income	$ 510,961	$ 587,430	$ 529,903
Adjustments for Noncash Items:			
Depreciation and Amortization	608,217	590,657	578,003
Deferred Federal Income Taxes	(6,549)	(21,478)	11,916
Deferred Investment Tax Credits	(25,241)	(25,808)	(25,819)
Amortization of Operating Expenses and Carrying Charges (net)	12,001	55,458	53,479
Extraordinary Item - UK Windfall Tax	109,419	-	-
Changes in Certain Current Assets and Liabilities:			
Accounts Receivable (net)	(136,186)	(39,049)	(71,804)
Fuel, Materials and Supplies	(1,427)	35,831	457
Accrued Utility Revenues	(14,225)	32,953	(40,433)
Accounts Payable	147,029	(13,915)	(31,044)
Taxes Accrued	(33,402)	(6,019)	37,515
Other (net)	27,325	41,002	14,437
Net Cash Flows From Operating Activities	1,197,922	1,237,062	1,056,610
INVESTING ACTIVITIES:			
Construction Expenditures	(760,394)	(577,691)	(605,974)
Investment in Yorkshire	(363,436)	-	-
Proceeds from Sale of Property and Other	2,142	12,283	20,567
Net Cash Flows Used For Investing Activities	(1,121,688)	(565,408)	(585,407)
FINANCING ACTIVITIES:			
Issuance of Common Stock	76,745	65,461	48,707
Issuance of Long-term Debt	880,522	407,291	523,476
Retirement of Cumulative Preferred Stock	(433,329)	(70,761)	(158,839)
Retirement of Long-term Debt	(348,157)	(601,278)	(469,767)
Change in Short-term Debt (net)	235,380	(45,430)	48,140
Dividends Paid on Common Stock	(453,453)	(449,353)	(445,831)
Net Cash Flows Used For Financing Activities	(42,292)	(694,070)	(454,114)
Net Increase (Decrease) in Cash and Cash Equivalents	33,942	(22,416)	17,089
Cash and Cash Equivalents January 1	57,539	79,955	62,866
Cash and Cash Equivalents December 31	$ 91,481	$ 57,539	$ 79,955

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(In Thousands - Except Share Data)

	December 31, 1997	December 31, 1996
ASSETS		
ELECTRIC UTILITY PLANT:		
Production	$ 9,493,158	$ 9,341,849
Transmission	3,501,580	3,380,258
Distribution	4,654,234	4,402,449
General (including mining assets and nuclear fuel)	1,604,671	1,491,781
Construction Work in Progress	342,842	353,832
Total Electric Utility Plant	19,596,485	18,970,169
Accumulated Depreciation and Amortization	7,963,636	7,549,798
NET ELECTRIC UTILITY PLANT	11,632,849	11,420,371
OTHER PROPERTY AND INVESTMENTS	1,358,810	892,674
CURRENT ASSETS:		
Cash and Cash Equivalents	91,481	57,539
Accounts Receivable:		
Customers (less allowance for uncollectible accounts of $6,760 in 1997 and $3,692 in 1996)	552,443	415,413
Miscellaneous	115,075	115,919
Fuel - at average cost	224,967	235,257
Materials and Supplies - at average cost	263,613	251,896
Accrued Utility Revenues	189,191	174,966
Prepayments and Other	81,366	103,891
TOTAL CURRENT ASSETS	1,518,136	1,354,881
REGULATORY ASSETS	1,817,540	1,889,482
DEFERRED CHARGES	288,011	325,580
TOTAL	$16,615,346	$15,882,988

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS

	December 31, 1997	December 31, 1996
CAPITALIZATION AND LIABILITIES		
CAPITALIZATION:		
Common Stock-Par Value $6.50:		
1997 / 1996		
Shares Authorized. .300,000,000 / 300,000,000		
Shares Issued. . . .198,989,981 / 197,234,992		
(8,999,992 shares were held in treasury)	$ 1,293,435	$ 1,282,027
Paid-in Capital	1,778,782	1,715,554
Retained Earnings	1,605,017	1,547,746
Total Common Shareholders' Equity	4,677,234	4,545,327
Cumulative Preferred Stocks of Subsidiaries:*		
Not Subject to Mandatory Redemption	46,724	90,323
Subject to Mandatory Redemption	127,605	509,900
Long-term Debt*	5,129,463	4,796,768
TOTAL CAPITALIZATION	9,981,026	9,942,318
OTHER NONCURRENT LIABILITIES	1,246,537	1,002,208
CURRENT LIABILITIES:		
Preferred Stock and Long-term Debt Due Within One Year*	294,454	86,942
Short-term Debt	555,075	319,695
Accounts Payable	353,256	206,227
Taxes Accrued	380,771	414,173
Interest Accrued	76,361	75,124
Obligations Under Capital Leases	101,089	89,553
Other	322,687	304,323
TOTAL CURRENT LIABILITIES	2,083,693	1,496,037
DEFERRED INCOME TAXES	2,560,921	2,643,143
DEFERRED INVESTMENT TAX CREDITS	376,250	401,491
DEFERRED GAIN ON SALE AND LEASEBACK - ROCKPORT PLANT UNIT 2	231,320	240,598
DEFERRED CREDITS	135,599	157,193
COMMITMENTS AND CONTINGENCIES (Note 4)		
TOTAL	$16,615,346	$15,882,988

*See Accompanying Schedules.

1. Significant Accounting Policies:

Organization - American Electric Power (AEP or the Company) is one of the U.S.'s largest investor-owned public utility holding companies engaged in the generation, purchase, transmission and distribution of electric power to nearly 3 million retail customers in its seven state service territory which covers portions of Ohio, Michigan, Indiana, Kentucky, West Virginia, Virginia and Tennessee. Electric power is also supplied at wholesale to neighboring utility systems and power marketers. AEP has holdings in the United States, the United Kingdom (UK) and China.

The organization of the AEP System consists of American Electric Power Company, Inc. (AEP Co., Inc.), the parent holding company; seven electric utility operating companies in the U.S. (domestic utility subsidiaries); a domestic generating subsidiary, AEP Generating Company (AEPGEN); a service company, American Electric Power Service Corporation (AEPSC); AEP Resources, Inc. (AEPR) which pursues energy-related domestic and international investment opportunities and projects; AEP Energy Services (AEPES) which markets and trades energy commodities; three active coal-mining companies and a group of subsidiaries that provide power engineering, consulting and management services around the world to complement utility activities.

The following domestic utility subsidiaries pool their generating and transmission facilities and operate them as an integrated system: Appalachian Power Company (APCo), Columbus Southern Power Company (CSPCo), Indiana Michigan Power Company (I&M), Kentucky Power Company and Ohio Power Company (OPCo). The remaining two domestic utility subsidiaries, Kingsport Power Company and Wheeling Power Company are distribution companies that purchase power from APCo and OPCo, respectively. AEPSC provides management and professional services to the AEP System. The active coal-mining companies are wholly-owned by OPCo and sell most of their production to OPCo. AEPGEN has a 50% interest in the Rockport Plant which is comprised of two of the AEP System's six 1,300 mw generating units. AEPR has investments and projects that include: a 50% interest in Yorkshire Electricity Group plc (Yorkshire), an electric distribution company in the UK (see Note 7); a 70% interest in a project to build two 125 mw coal-fired generating units in China. AEPES currently markets and trades natural gas. The non-regulated subsidiaries that complement utility activities are engaged in providing non-regulated energy and communication services and are seeking and considering new business opportunities domestically and internationally that will permit AEP to utilize its expertise and core competencies.

The AEP System's operations are divided into major business units which are managed centrally by AEPSC. Although the seven domestic utility subsidiaries and AEPSC are separate legal entities they operate as American Electric Power. There has been no change to the legal names of these companies.

Rate Regulation - The AEP System is subject to regulation by the Security and Exchange Commission (SEC) under the Public Utility Holding Company Act of 1935 (1935 Act). The rates charged by the domestic utility subsidiaries are approved by the Federal Energy Regulatory Commission (FERC) or the state utility commissions as applicable. The FERC regulates wholesale rates and the state commissions regulate retail rates.

Principles of Consolidation - The consolidated financial statements include AEP Co., Inc. and its wholly-owned and majority-owned subsidiaries consolidated with their wholly-owned subsidiaries. Significant intercompany items are eliminated in consolidation. Yorkshire is accounted for using the equity method.

Basis of Accounting - As the owner of cost-based rate-regulated electric public utility companies, AEP Co., Inc.'s consolidated financial statements 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 Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation," regulatory assets (deferred expenses) and regulatory liabilities (deferred income) are recorded to reflect the economic effects of regulation and to match expenses with regulated revenues.

Use of Estimates - The preparation of these financial statements in conformity with generally accepted accounting principles requires in certain instances the use of estimates. Actual results could differ from those estimates.

Utility Plant - Electric utility plant is stated at original cost and is generally subject to first mortgage liens. Additions, major replacements and betterments are added to the plant accounts. 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 utility plant are included in operating expenses.

Allowance for Funds Used During Construction (AFUDC) - AFUDC is a noncash nonoperating income item that is recovered over the service life of utility plant through depreciation and represents the estimated cost of borrowed and equity funds used to finance construction projects. The amounts of AFUDC for 1997, 1996 and 1995 were not significant.

Depreciation, Depletion and Amortization - Depreciation 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
Production:	
Steam-Nuclear	3.4%
Steam-Fossil-Fired	3.2% to 4.4%
Hydroelectric-Conventional and Pumped Storage	2.7% to 3.2%
Transmission	1.7% to 2.7%
Distribution	3.3% to 4.2%
General	2.5% to 3.8%

The utility subsidiaries presently recover amounts to be used for demolition and removal of non-nuclear plant through depreciation charges included in rates. Depreciation, depletion and amortization of coal-mining assets is provided over each asset's estimated useful life, ranging up to 30 years, 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 estimatec recoverable tonnages at a current average rate of $1.91 per ton. These costs are included in the cost of coal charged to fue expense.

Cash and Cash Equivalents - Cash and casł equivalents include temporary casł investments with original maturities of thre months or less.

Foreign Currency Translation - The financia statements of subsidiaries outside the Unite States are measured using the local currenc as the functional currency. Assets an

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. Translation adjustments are accumulated as a separate component of shareholders' equity. The accumulated total at December 31, 1997 is not material. Currency transaction gains and losses are recorded in income.

Sale of Receivables - Under an agreement that was terminated in January 1997, CSPCo sold $50 million of undivided interests in designated pools of accounts receivable and accrued utility revenues with limited recourse. As collections reduced previously sold pools, interests in new pools were sold. At December 31, 1996, $50 million remained to be collected and remitted to the buyer.

Operating Revenues and Fuel Costs - Revenues include the accrual of electricity consumed but unbilled at month-end as well as billed revenues. Fuel costs are matched with revenues in accordance with rate commission orders. Generally in the retail jurisdictions, changes in fuel costs are deferred or revenues accrued until approved by the regulatory commission for billing or refund to customers in later months. Wholesale jurisdictional fuel cost changes are expensed and billed as incurred.

Levelization of Nuclear Refueling Outage Costs - Incremental operation and maintenance costs associated with refueling outages at I&M's Cook Plant are deferred and amortized over the period (generally eighteen months) beginning with the commencement of an outage and ending with the beginning of the next outage.

Income Taxes - The Company follows the liability method of accounting for income taxes as prescribed by SFAS No. 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 rates, deferred income taxes are recorded with related regulatory assets and liabilities in accordance with SFAS No. 71.

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. Deferred investment tax credits are being amortized over the life of the related plant investment.

Debt and Preferred Stock - Gains and losses on reacquisition of debt are deferred and amortized over the remaining term of the reacquired debt in accordance with rate-making treatment. If the debt is refinanced, the reacquisition costs are deferred and amortized over the term of the replacement debt commensurate with their recovery in rates.

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

Redemption premiums paid to reacquire preferred stock 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.

Other Property and Investments - Excluding decommissioning and spent nuclear fuel disposal trust funds and the investment in Yorkshire, other property and investments are stated at cost. Securities held in trust funds for decommissioning nuclear facilities

and for the disposal of spent nuclear fuel are recorded at market value in accordance with SFAS No. 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. 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.

EPS - The adoption of SFAS No. 128 "Earnings per Share" had no impact on the determination of Earnings per Common Share.

2. Rate Matters:

OPCo's Recovery of Fuel Costs - Under the terms of a 1992 stipulation agreement the cost of coal burned at the Gavin Plant is subject to a 15-year predetermined price of $1.575 per million British Thermal Unit (Btu) with quarterly escalation adjustments through November 2009. A 1995 Settlement Agreement set the fuel component of the EFC factor at 1.465 cents per Kilowatthour (Kwh) for the period June 1, 1995 through November 30, 1998. The stipulation and settlement agreements provide OPCo with the opportunity to recover over the term of the stipulation agreement the Ohio jurisdictional share of OPCo's investment in and the liabilities and future shut-down costs of its affiliated mines as well as any fuel costs incurred above the predetermined rate to the extent the actual cost of coal burned at the Gavin Plant is below the predetermined prices. After full recovery of these costs or November 2009, whichever comes first, the price that OPCo can recover for coal from its affiliated Meigs mine which supplies the Gavin Plant will be limited to the lower of cost or the then-current market price. Pursuant to these agreements OPCo has deferred for future recovery $61 million at December 31, 1997.

Based on the estimated future cost of coal burned at Gavin Plant, management believes that the Ohio jurisdictional portion of the investment in and liabilities and closing costs of the affiliated mining operations including deferred amounts will be recovered under the terms of the predetermined price agreement. Management intends to seek from non-Ohio jurisdictional ratepayers recovery of the non-Ohio jurisdictional portion of the investment in and the liabilities and closing costs of the affiliated Meigs, Muskingum and Windsor mines. The non-Ohio jurisdictional portion of shutdown costs for these mines which includes the investment in the mines, leased asset buy-outs, reclamation costs and employee benefits is estimated to be approximately $102 million after tax at December 31, 1997.

The affiliated Muskingum and Windsor mines may have to close by January 2000 in order to comply with the Phase II requirements of the Clean Air Act Amendments of 1990 (CAAA). The Muskingum and/or Windsor mines could close prior to January 2000 depending on the economics of continued operation under the terms of the above Settlement Agreement. Unless future shutdown costs and/or the cost of affiliated coal production of the Meigs, Muskingum and Windsor mines can be recovered, results of operations and cash flows would be adversely affected.

3. Effects of Regulation and Phase-In Plans:

In accordance with SFAS No. 71 the consolidated financial statements include assets (deferred expenses) and liabilities (deferred income) recorded in accordance with regulatory actions to match expenses and revenues from cost-based rates. 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. The Company has reviewed all the evidence currently available and concluded that it continues to meet the requirements to apply SFAS No. 71. In the event a portion of the Company's business no longer met these requirements, net regulatory assets would have to be written off for that portion of the business and assets attributable to that portion of the business would have to be tested for possible impairment and if required an impairment loss recorded unless the net regulatory assets and impairment losses are recoverable as a stranded investment.

Recognized regulatory assets and liabilities are comprised of the following at:

	December 31, 1997	December 31, 1996
	(In Thousands)	
Regulatory Assets:		
Amounts Due From Customers For Future Income Taxes	$1,372,926	$1,459,086
Rate Phase-in Plan Deferrals	-	27,249
Unamortized Loss on Reacquired Debt	96,793	107,305
Other	347,821	295,842
Total Regulatory Assets	$1,817,540	$1,889,482
Regulatory Liabilities:		
Deferred Investment Tax Credits	$376,250	$401,491
Other Regulatory Liabilities*	78,802	86,609
Total Regulatory Liabilities	$455,052	$488,100

* Included in Deferred Credits on Consolidated Balance Sheets

The rate phase-in plan deferrals are applicable to the Zimmer Plant and Rockport Plant Unit 1. The Zimmer Plant is a 1,300 mw coal-fired plant which commenced commercial operation in 1991. CSPCo owns 25.4% of the plant with the remainder owned by two unaffiliated companies. As a result of an Ohio Supreme Court decision, in January 1994 the Public Utility Commission of Ohio (PUCO) approved a temporary 3.39% surcharge effective February 1, 1994. In June 1997 the Company completed recovery of its Zimmer Plant phase-in plan deferrals and discontinued the 3.39% temporary rate surcharge. In 1997, 1996 and 1995 $15.4 million, $31.5 million and $28.5 million, respectively, of net phase-in deferrals were collected through the surcharge. The deferral balance which was completely recovered and amortized in 1997 was $15.4 million at December 31, 1996.

The Rockport Plant consists of two 1,300 mw coal-fired units. I&M and AEPGEN each own 50% of one unit (Rockport 1) and lease a 50% interest in the other unit (Rockport 2) from unaffiliated lessors under an operating lease. The gain on the sale and leaseback of Rockport 2 was deferred and is being amortized, with related taxes, over the initial lease term which expires in 2022. A rate phase-in plan in the Indiana and the FERC jurisdictions provide for the recovery and straight-line amortization of deferred Rockport Plant Unit 1 costs over ten years beginning in 1987. In 1997 the amortization and recovery of the deferred Rockport Plant Unit 1 Phase-in Plan costs were completed. During the recovery period net income was unaffected by the recovery of the phase in deferrals. Amortization was $11.9 million in 1997 and $16 million in 1996 and 1995.

4. Commitments and Contingencies:

Construction and Other Commitments - The AEP System has substantial construction commitments to support its utility operations including the replacement of the Cook Plant Unit 1 steam generators. Such commitments do not presently include any expenditures for new generating capacity. Aggregate construction expenditures for 1998-2000 are estimated to be $2.4 billion.

Long-term fuel supply contracts contain clauses for periodic price adjustments, and most jurisdictions have fuel clause mechanisms that provide for recovery of changes in the cost of fuel with the regulators' review and approval. The contracts are for various terms, the longest of

which extends to the year 2014, and contain various clauses that would release the Company from its obligation under certain force majeure conditions.

The AEP System has contracted to sell approximately 1,000 mw of capacity on a long-term basis to unaffiliated utilities. Certain contracts totaling 750 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 1999 to 2010.

Nuclear Plant - I&M owns and operates the two-unit 2,110 mw Cook Plant under licenses granted by the Nuclear Regulatory Commission (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 United States, the resultant liability could be substantial. By agreement I&M is partially liable together with all other electric utility companies that own nuclear generating units for a nuclear power plant incident. 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 could be negatively affected.

Nuclear Plant Shutdown - On September 9 and 10, 1997, during a NRC architect engineer design inspection, questions regarding the operability of certain safety systems caused Company operations personnel to shut down Units 1 and 2 of the Cook Plant. On September 19, 1997, the NRC issued a Confirmatory Action Letter requiring the Company to address the issues identified in the letter. The Company is working with the NRC to resolve these issues and other issues related to restart of the units. Certain issues identified in the letter have been addressed. At this time management is unable to determine when the units will be returned to service. If the units are not returned to service in a reasonable period of time, it could have an adverse impact on results of operations, cash flows and possibly financial condition.

Nuclear Incident Liability - Public liability is limited by law to $8.9 billion should an incident occur at any licensed reactor in the United States. Commercially available insurance provides $200 million of coverage. In the event of a nuclear incident at any nuclear plant in the United States the remainder of the liability would be provided by a deferred premium assessment of $79.3 million on each licensed reactor payable in annual installments of $10 million. As a result, I&M could be assessed $158.6 million per nuclear incident payable in annual installments of $20 million. The number of incidents for which payments could be required is not limited.

Nuclear insurance pools and other insurance policies provide $3.6 billion (reduced to $3.0 billion effective January 1, 1998) of property damage, decommissioning and decontamination coverage for the Cook Plant. Additional insurance provides coverage for extra costs resulting from a prolonged accidental Cook Plant outage. Some of the policies have deferred premium provisions which could be triggered by losses in excess of the insurer's resources. The losses could result from claims at the Cook Plant or certain other non-affiliated nuclear units. I&M could be assessed up to $35.8 million under these policies.

SNF Disposal - Federal law provides for government responsibility for permanent spent nuclear fuel disposal and assesses nuclear plant owners fees for spent fuel disposal. A fee of one mill per kilowatthour for fuel consumed after April 6, 1983 is being collected from customers and remitted to the U.S. Treasury. Fees and related interest of $181 million for fuel consumed prior to April 7, 1983 have been recorded as long-term

debt. I&M has not paid the government the pre-April 1983 fees due to continued delays and uncertainties related to the federal disposal program. At December 31, 1997, funds collected from customers towards payment of the pre-April 1983 fee and related earnings thereon approximate the liability.

Decommissioning and Low Level Waste Accumulation Disposal - Decommissioning costs are accrued over the service life of the Cook Plant. The licenses to operate the two nuclear units expire in 2014 and 2017. After expiration of the licenses the plant is expected to be decommissioned through dismantlement. The Company's latest estimate for decommissioning and low level radioactive waste accumulation disposal costs range from $700 million to $1,152 million in 1997 nondiscounted dollars. The wide range is caused by variables in assumptions including the estimated length of time spent nuclear fuel must be stored at the plant 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 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. I&M records decommissioning costs in other operation expense and records a noncurrent liability equal to the decommissioning cost recovered in rates; such amounts were $28 million in 1997, $27 million in 1996 and $30 million in 1995 including $4 million of special deposits. Decommissioning costs recovered from customers are deposited in external trusts. Trust fund earnings increase the fund assets and the recorded liability and decrease the amount needed to be recovered from ratepayers. At December 31, 1997, I&M has recognized a decommissioning liability of $381 million which is included in other noncurrent liabilities.

Revised Air Quality Standards - On July 18, 1997, the Federal EPA published a revised National Ambient Air Quality Standard (NAAQS) for ozone and a new NAAQS for fine particulate matter (less than 2.5 microns in size). The new ozone standard is expected to result in redesignation of a number of areas of the country that are currently in compliance with the existing standard to nonattainment status which could ultimately dictate more stringent emission restrictions for AEP System generating units. New stringent emission restrictions on AEP System generating units to achieve attainment of the fine particulate matter standard could also be imposed. The AEP System operating companies joined with other utilities to appeal the revised NAAQS and filed petitions for review in August and September 1997 in the U.S. Court of Appeals for the District of Columbia Circuit. Management is unable to estimate compliance costs without knowledge of the reductions that may be necessary to meet the new standards. If such costs are significant, it could have a material adverse effect on results of operations, cash flows and possibly financial condition unless such costs are recovered.

Litigation - The Company is involved in a number of legal proceedings and claims. While management is unable to predict the ultimate outcome of litigation, it is not expected that the resolution of these matters will have a material adverse effect on the results of operations, cash flows or financial condition.

5. Dividend Restrictions:

Mortgage indentures, charter provisions and orders of regulatory authorities place various restrictions on the use of the subsidiaries'

retained earnings for the payment of cash dividends on their common stocks. At December 31, 1997, $27 million of retained earnings were restricted. To pay dividends out of paid-in capital the subsidiaries need regulatory approval.

6. Lines of Credit and Commitment Fees:

At December 31, 1997 and 1996, unused short-term bank lines of credit were available in the amounts of $442 million and $409 million, respectively. In addition several of the subsidiaries engaged in providing non-regulated energy services share a line of credit under a revolving credit agreement. The amounts of credit available under the revolving credit agreement were $330 million and $100 million at December 31, 1997 and 1996, respectively. The short-term bank lines of credit and the revolving credit agreement require the payment of facility fees of approximately 1/10 of 1% on the daily amount of such commitments.

Outstanding short-term debt consisted of:

(Dollars In Thousands)	December 31, 1997	December 31, 1996
Balance Outstanding:		
Notes Payable	$199,285	$ 91,293
Commercial Paper	355,790	228,402
Total	$555,075	$319,695
Year-End Weighted Average Interest Rate:		
Notes Payable	6.3%	6.2%
Commercial Paper	6.8%	7.2%
Total	6.6%	6.9%

7. Yorkshire Acquisition and UK Windfall Tax

In April 1997 the Company and New Century Energies, Inc. through an equally owned joint venture, Yorkshire Power Group Limited (YPG), acquired all of the outstanding shares of Yorkshire, an electric distribution company in the UK. Total consideration paid by the joint venture was approximately $2.4 billion which was financed by a combination of equity and non-recourse debt. The Company uses the equity method of accounting for its investment in YPG. The Company's original investment in the joint venture was $360 million and is included in other property and investments.

In July 1997 the British government enacted a new law that imposed a one-time windfall tax on a revised privatization value which originally had been computed in 1990 on certain privatized utilities. The windfall tax is actually an adjustment of the original privatization price by the UK government. The windfall tax liability for Yorkshire Electricity Group plc is estimated to be 134 million pounds sterling ($219 million) and is payable in two equal installments. The first payment was made in December 1997 and the second installment will be due in December 1998. The Company's $109.4 million share of the tax is reported as an extraordinary loss. The equity earnings from the Yorkshire investment, excluding the extraordinary loss, which are included in nonoperating income, are $34 million inclusive of $10 million of nonrecurring tax benefits related to a reduction of the UK corporate income tax rate from 33% to 31% effective April 1, 1997.

The following amounts which are not included in AEP's consolidated financial statements represent summarized consolidated financial information of YPG at December 31, 1997 and for the nine-months then ended:

	(In Millions)
Assets:	
Property, Plant and Equipment	$1,644.6
Current Assets	602.2
Other Assets	1,895.4
Total Assets	$4,142.2
Capitalization and Liabilities:	
Common Shareholders' Equity	$ 542.1
Long-term Debt	704.3
Other Noncurrent Liabilities	488.7
Current Liabilities	2,407.1
Total Capitalization and Liabilities	$4,142.2
Income Statement Data:	
Operating Revenues	$1,492.9
Operating Income	202.3
Income Before Extraordinary Item	67.5
Net Loss	(151.3)

8. Benefit Plans:

AEP System Pension Plan - The AEP pension plan is a trusteed, noncontributory defined benefit plan covering all employees meeting eligibility requirements, except participants in the United Mine Workers of America (UMWA) pension plans. Benefits are based on service years and compensation levels. The funding policy is to make annual contributions to a qualified trust fund equal to the net periodic pension cost up to the maximum amount deductible for federal income taxes, but not less than the minimum required contribution in accordance with the Employee Retirement Income Security Act of 1974.

Net AEP pension plan costs were computed as follows:

	Year Ended December 31,		
	1997	1996	1995
	(In Thousands)		
Service Cost-Benefits Earned During the Year	$ 36,000	$ 40,000	$ 30,400
Interest Cost on Projected Benefit Obligation	128,600	119,500	116,700
Actual Return on Plan Assets	(462,700)	(302,400)	(416,800)
Net Amortization (Deferral)	307,700	161,800	281,800
Net AEP Pension Plan Costs	$ 9,600	$ 18,900	$ 12,100

AEP pension plan assets, actuarially computed benefit obligations and the computation of accrued net pension plan liability are:

	December 31,	
	1997	1996
	(In Thousands)	
Actuarial Present Value of Benefit Obligation:		
Vested Obligation	$1,523,200	$1,377,000
Nonvested Obligation	161,000	136,500
Effects of Salary Progression	205,800	162,700
Projected Benefit Obligation	1,890,000	1,676,200
AEP Pension Plan Assets at Fair Value (a)	2,370,300	2,009,500
Funded Status - AEP Pension Plan Assets in Excess of Projected Benefit Obligation	480,300	333,300
Unrecognized Prior Service Cost	119,400	133,200
Unrecognized Net Gain on Assets	(640,800)	(488,200)
Unrecognized Net Transition Assets (Being Amortized Over 17 Years)	(59,100)	(68,900)
Accrued Net AEP Pension Plan Liability	$ (100,200)	$ (90,600)

(a) AEP pension plan assets primarily consist of common stocks, bonds and cash equivalents and are included in a separate entity trust fund.

Assumptions used to determine AEP's net pension plan liability were:

	December 31,		
	1997	1996	1995
Discount Rate	7.00%	7.75%	7.25%
Average Rate of Increase in Compensation Levels	3.2%	3.2%	3.2%
Expected Long-Term Rate of Return on Plan Assets	9.0%	9.0%	9.0%

Postretirement Benefits Other Than Pensions (OPEB) - The AEP System provides certain benefits other than pensions for retired employees. Substantially all non-UMWA employees are eligible for postretirement health care and life insurance if they retire from active service after reaching age 55 and have at least 10 service years.

Postretirement medical benefits for UMWA employees at affiliated mining operations who have or will retire after January 1, 1976 are the liability of the OPCo coal-mining subsidiaries and are included in the OPEB net costs and liability. They are eligible for postretirement medical benefits if they retire from active service after reaching age 55 and have at least 10 service years. In addition, non-active UMWA employees will become eligible for postretirement benefits at age 55 if they have had 20 years of service.

The funding policy for AEP's OPEB plan is to make contributions to an external Voluntary Employees Beneficiary Association trust fund equal to the incremental OPEB costs (i.e., the amount that the total postretirement benefits cost under SFAS 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions," exceeds the pay-as-you-go amount). Contributions were $35.2 million in 1997, $45.8 million in 1996 and $53 million in 1995. In several jurisdictions the utility subsidiaries deferred the increased OPEB costs resulting from the SFAS 106 required change from pay-as-you-go to accrual accounting which were not being recovered in rates. No additional deferrals were made

in 1997 or 1996. At December 31, 1997 and 1996, $7.9 million and $14.5 million, respectively, of incremental OPEB costs were deferred.

Aggregate OPEB costs were computed as follows:

	Year Ended December 31,		
	1997	1996	1995
	(In Thousands)		
Service Cost	$ 14,000	$ 15,300	$13,500
Interest Cost on Projected Benefit Obligation	55,900	53,500	54,900
Net Amortization of the Transition Obligation	32,000	32,300	32,000
Return on Plan Assets	(44,100)	(21,100)	(25,400)
Net Amortization (Deferral)	21,500	9,900	16,800
Net OPEB Costs	$ 79,300	$ 89,900	$91,800

OPEB assets, actuarially computed benefit obligations and the computation of the accrued net OPEB liability are:

	December 31,	
	1997	1996
	(In Thousands)	
Accumulated Postretirement Benefit Obligation:		
Active Employees Fully Eligible for Benefits	$ 73,800	$ 57,800
Current Retirees	466,900	423,000
Other Active Employees	309,000	245,600
Total Benefit Obligation	849,700	726,400
Fair Market Value of Plan Assets (a)	311,900	232,500
Unfunded Benefit Obligation	(537,800)	(493,900)
Unrecognized Net Loss (Gain)	66,100	(3,300)
Unrecognized Net Transition Obligation Being Amortized Over 20 Years	416,400	448,500
Accrued Net OPEB Liability	$ (55,300)	$(48,700)

(a) Plan assets consist of cash surrender value of life insurance contracts on certain employees owned by the trust and short-term tax-exempt municipal bonds.

Assumptions used to determine OPEB's funded status were:

	December 31,		
	1997	1996	1995
Discount Rate	7.00%	7.75%	7.25%
Expected Long-Term Rate of Return on Plan Assets	8.75%	8.75%	8.75%
Initial Medical Cost Trend Rate	7.0%	7.5%	8.0%
Ultimate Medical Cost Trend Rate	4.25%	4.75%	4.5%
Medical Cost Trend Rate Decreases to Ultimate Rate in Year	2005	2005	2005

Assuming a one percent increase in the medical cost trend rate, the 1997 OPEB cost for all employees, both non-UMWA and UMWA, would increase by $10 million and the accumulated benefit obligations would increase by $92 million.

AEP System Savings Plan - An employee savings plan is offered to non-UMWA employees which allows participants to contribute up to 17% of their salaries into various investment alternatives, including AEP common stock. An employer matching contribution, equaling one-half of the employees' contribution to the plan up to a maximum of 3% of the employees' base salary, is invested in AEP common stock. The employer's annual contributions totaled $19.6 million in 1997, $19 million in 1996 and $18.8 million in 1995.

Other UMWA Benefits - The Company provides UMWA pension, health and welfare benefits for certain 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 based on hours worked are expensed as paid as part of the cost of active mining operations and were not material in 1997, 1996 and 1995. Based upon the UMWA actuary estimate the Company's share of unfunded pension liability was $6.9 million at June 30, 1997. In the event the Company should significantly reduce or cease mining operations or contributions to the UMWA trust funds, a withdrawal obligation will be triggered for both the pension and health and welfare plans. If the mining operations had been closed on December 31, 1997 the estimated withdrawal liability for all UMWA benefit plans would have been $6.7 million.

9. Fair Value of Financial Instruments:

Nuclear Trust Funds Recorded at Market Value - The trust investments, reported in other property and investments, are recorded at market value in accordance with SFAS No.

115 and consist of tax-exempt municipal bonds and other securities.

At December 31, 1997 and 1996 the fair values of the trust investments were $566 million and $491 million, respectively. Accumulated gross unrealized holding gains were $41 million and $21.9 million at December 31, 1997 and 1996, respectively and accumulated gross unrealized holding losses were $1.2 million at both year-ends. The change in market value in 1997, 1996, and 1995 was a net unrealized holding gain of $19.1 million, $2.6 million and $24.9 million, respectively.

The trust investments' cost basis by security type were:

	December 31, 1997	December 31, 1996
	(In Thousands)	
Tax-Exempt Bonds	$335,358	$340,290
Equity Securities	74,398	54,389
Treasury Bonds	44,200	26,958
Corporate Bonds	9,167	7,977
Cash, Cash Equivalents and Accrued Interest	63,392	40,430
Total	$526,515	$470,044

Proceeds from sales and maturities of securities of $147.3 million during 1997 resulted in $3.9 million of realized gains and $1.4 million of realized losses. Proceeds from sales and maturities of securities of $115.3 million during 1996 resulted in $2.6 million of realized gains and $2.1 million of realized losses. During 1995 proceeds from sales and maturities of securities of $78.2 million resulted in $1.4 million of realized gains and $0.3 million of realized losses. The cost of securities for determining realized gains and losses is original acquisition cost including amortized premiums and discounts.

At December 31, 1997, the year of maturity of trust fund investments other than equity securities, was:

	(In Thousands)
1998	$ 87,063
1999 - 2002	127,575
2003 - 2007	182,873
After 2007	54,606
Total	$452,117

Other Financial Instruments Recorded at Historical Cost - The carrying amounts 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. Fair values for preferred stock subject to mandatory redemption were $136 million and $517 million and for long-term debt were $5.7 billion and $5.0 billion at December 31, 1997 and 1996, respectively. The carrying amounts on the financial statements for preferred stock subject to mandatory redemption were $128 million and $510 million and for long-term debt were $5.4 billion and $4.9 billion at December 31, 1997 and 1996, respectively. Fair values 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 carrying amount of the spent nuclear fuel disposal trust funds approximates the Company's best estimate of the fair value of the pre-April 1983 SNF disposal liability.

10. Federal Income Taxes:

The details of federal income taxes as reported are as follows:

	Year Ended December 31,		
	1997	1996	1995
	(In Thousands)		
Charged *(Credited)* to Operating Expenses (net):			
Current	$346,290	$375,528	$265,313
Deferred	11,124	(17,008)	22,990
Deferred Investment Tax Credits	(16,134)	(16,298)	(16,276)
Total	341,280	342,222	272,027
Charged *(Credited)* to Nonoperating Income (net):			
Current	(16,038)	(5,636)	11,325
Deferred	(17,673)	(4,470)	(11,074)
Deferred Investment Tax Credits	(9,107)	(9,510)	(9,543)
Total	(42,818)	(19,616)	(9,292)
Total Federal Income Tax as Reported	$298,462	$322,606	$262,735

The following is a reconciliation 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 federal income taxes reported.

	Year Ended December 31,		
	1997	1996	1995
	(In Thousands)		
Income Before Preferred Stock Dividend Requirements of Subsidiaries	$ 638,211	$628,856	$584,674
Extraordinary Loss (Note 7)	(109,419)	-	-
Federal Income Taxes	298,462	322,606	262,735
Pre-Tax Book Income	$ 827,254	$951,462	$847,409
Federal Income Tax on Pre-Tax Book Income at Statutory Rate *(35%)*	$289,539	$333,012	$296,593
Increase (Decrease) in Federal Income Tax Resulting from the Following Items:			
Depreciation	53,239	50,537	46,453
Corporate Owned Life Insurance	(18,240)	(12,009)	(25,506)
Investment Tax Credits (net)	(25,241)	(25,813)	(26,179)
Extraordinary Loss - UK Windfall Tax	38,297	-	-
Other	(39,132)	(23,121)	(28,626)
Total Federal Income Taxes as Reported	$298,462	$322,606	$262,735
Effective Federal Income Tax Rate	36.1%	33.9%	31.0%

The following tables show the elements of the net deferred tax liability and the significant temporary differences:

	December 31, 1997	December 31, 1996
	(In Thousands)	
Deferred Tax Assets	$ 807,226	$ 784,349
Deferred Tax Liabilities	(3,368,147)	(3,427,492)
Net Deferred Tax Liabilities	$(2,560,921)	$(2,643,143)
Property Related Temporary Differences	$(2,161,484)	$(2,162,099)
Amounts Due From Customers For Future Federal Income Taxes	(410,255)	(428,698)
Deferred State Income Taxes	(201,843)	(229,429)
All Other (net)	212,661	177,083
Total Net Deferred Tax Liabilities	$(2,560,921)	$(2,643,143)

The Company has settled with the United States Internal Revenue Service (IRS) all issues from the audits of the consolidated federal income tax returns for the years prior to 1991. Returns for the years 1991 through 1996 are presently being audited by the IRS. During the audit the IRS agents requested a ruling from their National Office that certain interest deductions relating to corporate owned life insurance (COLI) claimed by the Company for 1991 through 1993 should not be allowed. The Company filed a brief with the IRS National Office refuting the agents' position. Although no adjustments have been proposed, a disallowance of the COLI interest deductions through December 31, 1997 would reduce earnings by approximately $286 million (including interest). AEP believes it has meritorious defenses and will vigorously contest any proposed adjustments. No provisions for this amount have been recorded. In the event the Company is unsuccessful it could have a material adverse impact on results of operations and cash flows.

11. 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 are primarily charged to operating expenses in accordance with rate-making treatment. The components of rentals are as follows:

	Year Ended December 31, 1997	1996	1995
	(In Thousands)		
Operating Leases	$257,042	$262,451	$259,877
Amortization of Capital Leases	104,732	114,050	101,068
Interest on Capital Leases	31,601	28,696	27,542
Total Rental Payments	$393,375	$405,197	$388,487

Properties under capital leases and related obligations on the Consolidated Balance Sheets are as follows:

	December 31, 1997	December 31, 1996
	(In Thousands)	
ELECTRIC UTILITY PLANT:		
Production	$ 47,246	$ 44,390
Transmission	3	6
Distribution	14,660	14,699
General:		
Nuclear Fuel (net of amortization)	103,939	59,681
Mining Plant and Other	516,843	466,797
Total Electric Utility Plant	682,691	585,573
Accumulated Amortization	196,145	200,931
Net Electric Utility Plant	486,546	384,642
OTHER PROPERTY	57,763	33,439
Accumulated Amortization	5,917	3,854
Net Other Property	51,846	29,585
Net Property under Capital Leases	$538,392	$414,227
Capital Lease Obligations:*		
Noncurrent Liability	$437,303	$324,674
Liability Due Within One Year	101,089	89,553
Total Capital Lease Obligations	$538,392	$414,227

*Represents the present value of future minimum lease payments. The noncurrent portion of capital lease obligations is included in other noncurrent liabilities in the Consolidated Balance Sheet.

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

Future minimum lease rentals, consisted of the following at December 31, 1997:

	Capital Leases		Noncancelable Operating Leases
	(In Thousands)		
1998	$104,623		$ 243,042
1999	92,740		229,764
2000	79,507		228,044
2001	64,438		225,482
2002	59,400		220,111
Later Years	164,371		3,577,422
Total Future Minimum Lease Rentals	565,079	(a)	$4,723,865
Less Estimated Interest Element	130,626		
Estimated Present Value of Future Minimum Lease Rentals	434,453		
Unamortized Nuclear Fuel	103,939		
Total	$538,392		

(a) Minimum lease rentals do not include nuclear fuel rentals. The rentals 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.

12. Supplementary Information:

	Year Ended December 31,		
	1997	1996	1995
	(In Thousands)		
Purchased Power - Ohio Valley Electric Company (44.2% owned by AEP System)	$29,631	$22,156	$10,546
Cash was paid for:			
Interest (net of capitalized amounts)	$390,491	$373,570	$395,169
Income Taxes	$398,833	$404,297	$273,671
Noncash Acquisitions under Capital Leases	$234,846	$136,988	$106,256

13. Capital Stocks and Paid-In Capital:

Changes in capital stocks and paid-in capital during the period January 1, 1995 through December 31, 1997 were:

	Shares		(Dollars in Thousands)		Cumulative Preferred Stocks of Subsidiaries	
	Common Stock-Par Value $6.50(a)	Cumulative Preferred Stocks of Subsidiaries	Common Stock	Paid-in Capital	Not Subject To Mandatory Redemption	Subject to Mandatory Redemption(b)
January 1, 1995	194,234,992	8,236,251	$1,262,527	$1,640,661	$ 233,240	$590,385
Issuances	1,400,000	-	9,100	39,607	-	-
Retirements and Other	-	(1,526,500)	-	(21,744)	(85,000)	(67,650)
December 31, 1995	195,634,992	6,709,751	1,271,627	1,658,524	148,240	522,735
Issuances	1,600,000	-	10,400	55,061	-	-
Retirements and Other	-	(707,518)	-	1,969	(57,917)	(12,835)
December 31, 1996	197,234,992	6,002,233	1,282,027	1,715,554	90,323	509,900
Issuances	1,754,989	-	11,408	65,337	-	-
Retirements and Other	-	(4,258,947)	-	(2,109)	(43,599)	(382,295)
December 31, 1997	198,989,981	1,743,286	$1,293,435	$1,778,782	$ 46,724	$127,605

(a) Includes 8,999,992 shares of treasury stock.
(b) Including portion due within one year.

14. Unaudited Quarterly Financial Information:

(In Thousands - Except Per Share Amounts)	Quarterly Periods Ended 1997 March 31	June 30	Sept. 30	Dec. 31
Operating Revenues	$1,492,069	$1,382,158	$1,583,994	$1,703,147
Operating Income	271,978	221,255	275,090	216,131
Net Income Before Extraordinary Item	172,562	121,139	201,746	124,933
Net Income	172,562	121,139	91,181	126,079
Earnings per Share Before Extraordinary Item*	0.92	0.64	1.07	0.66
Earnings per Share	0.92	0.64	0.48	0.66

*Amounts for 1997 do not add to $3.28 earnings per share due to rounding.

The third quarter of 1997 includes an extraordinary loss of $110.6 million or $0.59 per share for a UK Windfall Tax which retroactively adjusted upward Yorkshire's privatization price discussed in Note 7.

(In Thousands - Except Per Share Amounts)	Quarterly Periods Ended 1996 March 31	June 30	Sept. 30	Dec. 31
Operating Revenues	$1,517,781	$1,400,941	$1,484,422	$1,446,090
Operating Income	292,122	220,625	259,745	235,480
Net Income	180,012	112,666	162,324	132,428
Earnings per Share	0.96	0.60	0.87	0.71

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES

SCHEDULE OF CONSOLIDATED CUMULATIVE PREFERRED STOCKS OF SUBSIDIARIES

	December 31, 1997			
	Call Price per Share (a)	Shares Authorized(b)	Shares Outstanding	Amount (In Thousands)
Not Subject to Mandatory Redemption:				
4.08% - 4.56% (c)	$102-$110	932,403	467,236	$ 46,724
Subject to Mandatory Redemption:				
5.90% - 5.92% (c)(d)	(e)	1,950,000	388,100	$ 38,810
6.02% - 6-7/8% (c)(d)	(f)	1,950,000	637,950	63,795
7% (g)	(g)	250,000	250,000	25,000
Total Subject to Mandatory Redemption (d)				$127,605

	December 31, 1996			
	Call Price per Share (a)	Shares Authorized(b)	Shares Outstanding	Amount (In Thousands)
Not Subject to Mandatory Redemption:				
4.08% - 4.56%	$102-$110	932,403	903,233	$ 90,323
Subject to Mandatory Redemption (d):				
5.90% - 5.92%	(e)	1,950,000	1,904,000	$190,400
6.02% - 6-7/8%	(f)	1,950,000	1,945,000	194,500
7% - 7-7/8%	$107.80-$107.88	1,250,000	1,250,000	125,000
Total Subject to Mandatory Redemption (d)				$509,900

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, 1997 the subsidiaries had 7,189,682, 22,200,000 and 7,579,435 shares of $100, $25 and no par value preferred stock, respectively, that were authorized but unissued.

(c) During the first quarter of 1997 preferred stock was reacquired in connection with a tender offer.

(d) 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 $5,000,000 each for the years 2000, 2001 and 2002.

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

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

(g) With sinking fund. Redemption is restricted prior to 2000.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES

SCHEDULE OF CONSOLIDATED LONG-TERM DEBT OF SUBSIDIARIES

Maturity	Weighted Average Interest Rate December 31, 1997	Interest Rates at December 31, 1997	Interest Rates at December 31, 1996	December 31, 1997	December 31, 1996
				(In Thousands)	
FIRST MORTGAGE BONDS					
1997-2000	7.20%	6.35%-9.15%	6-1/4%-9.15%	$ 466,411	$ 383,671
2001-2006	7.10%	6%-8.95%	6%-8.95%	1,511,000	1,511,000
2021-2025	7.95%	7.10%-8.80%	7.10%-9.35%	1,120,419	1,276,750
INSTALLMENT PURCHASE CONTRACTS (a)					
1998-2002	4.60%	3.70%-7-1/4%	4.10%-7-1/4%	189,500	209,500
2007-2025	6.45%	5.45%-7-7/8%	5.45%-7-7/8%	756,745	756,745
NOTES PAYABLE (b)					
1997-2008	6.73%	5.29%-9.60%	5.29%-9.60%	671,681	282,681
JUNIOR DEBENTURES					
2025 - 2027	8.17%	7.92%-8.72%	8%-8.72%	495,000	315,000
OTHER LONG-TERM DEBT (c)				250,357	182,943
Unamortized Discount (net)				(37,196)	(34,580)
Total Long-term Debt Outstanding (d)				5,423,917	4,883,710
Less Portion Due Within One Year				294,454	86,942
Long-term Portion				$5,129,463	$4,796,768

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 and unsecured medium term notes issued to the public. 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 4 of the Notes to Consolidated Financial Statements) and financing obligation under sale lease back agreements.
(d) Long-term debt outstanding at December 31, 1997 is payable as follows:

Principal Amount (in thousands)

1998	$ 294,454
1999	491,579
2000	321,286
2001	267,040
2002	484,533
Later Years	3,602,221
Total	$5,461,113

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 - Certified Public Accountants 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 a review 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 accompanying consolidated balance sheets of American Electric Power Company, Inc. and its subsidiaries as of December 31, 1997 and 1996, and the related consolidated statements of income, retained earnings, and cash flows for each of the three years in the period ended December 31, 1997. 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 generally accepted auditing standards. 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 American Electric Power Company, Inc. and its subsidiaries as of December 31, 1997 and 1996, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1997 in conformity with generally accepted accounting principles.

Deloitte & Touche LLP

Deloitte & Touche LLP
Columbus, Ohio
February 24, 1998

Indiana Michigan Power Company

1997 Annual Report

AEP AMERICAN ELECTRIC POWER

One Summit Square, P.O. Box 60, Fort Wayne, Indiana 46801

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INVESTOR INQUIRIES
Investors should direct inquiries to Investor Relations using the toll free number:
1-800-AEP-COMP (1-800-237-2667) or by writing to:
Bette Jo Rozsa
Investor Relations
American Electric Power Service Corporation
28th Floor
1 Riverside Plaza
Columbus, OH 43215-2373

FORM 10-K ANNUAL REPORT
The Annual Report (Form 10-K) to the Securities and Exchange Commission will be available in April 1998 at no cost to shareholders. Please address requests for copies to:
Geoffrey C. Dean
American Electric Power Service Corporation
26th Floor
1 Riverside Plaza
Columbus, OH 43215-2373

TRANSFER AGENT AND REGISTRAR OF CUMULATIVE PREFERRED STOCK
First Chicago Trust Company of New York
P.O. Box 2534
Suite 4692
Jersey City, NJ 07303-2534

BACKGROUND

INDIANA MICHIGAN POWER COMPANY (the Company) is engaged in the generation, sale, purchase, transmission and distribution of electric power. The Company serves approximately 549,000 retail customers in northern and eastern Indiana and a portion of southwestern Michigan and sells and transmits power at wholesale to other electric utilities, municipalities, electric cooperatives and non-utility entities engaged in the wholesale power market. Approximately 86% of the Company's retail sales are in Indiana and 14% in Michigan. The principal industries served are primary metals, electrical and electronic machinery, transportation equipment, chemicals and allied products, fabricated metal products and rubber and miscellaneous plastic products.

The Company, which was organized under the laws of Indiana on February 21, 1925, is a subsidiary of American Electric Power Company, Inc., a public utility holding company. The Company does business as American Electric Power (AEP) along with all of the parent's operating subsidiary companies in order to serve its customers more efficiently as one operating organization aligned by distinct business units. The Company's two wholly-owned subsidiaries, Blackhawk Coal Company and Price River Coal Company, were formerly engaged in coal-mining operations in Utah. Blackhawk Coal Company currently leases or subleases portions of its coal rights, land and related mining equipment to unaffiliated companies. In addition, the Company has a river transportation division (RTD) that barges coal on the Ohio and Kanawha Rivers to AEP System generating plants. The RTD also provides some barging services to unaffiliated companies.

The Company owns and leases 4,435 megawatts (mw) of generating capacity which includes 2,295 mw of coal-fired generation and 2,110 mw of nuclear generation. The Company owns the two unit Donald C. Cook Nuclear Plant located in Michigan. The generating plants and transmission facilities of the Company and certain other affiliated AEP System utility subsidiaries are operated as an integrated system with their costs and benefits shared through the AEP System Power Pool and AEP Transmission Agreement. Wholesale energy sales made by the Power Pool are allocated to the Company and the other Pool members. The other AEP System Pool members are: Appalachian Power Company, Columbus Southern Power Company, Kentucky Power Company and Ohio Power Company. The Company is interconnected with two other affiliated companies, Kingsport Power Company and Wheeling Power Company that are not members of the Power Pool, and with numerous unaffiliated utilities through the AEP System. In addition, the Company is also directly interconnected with its affiliate, AEP Generating Company, and the following unaffiliated entities: Central Illinois Public Service Company, The Cincinnati Gas & Electric Company, Commonwealth Edison Company, Consumers Energy Corporation, Illinois Power Company, Indianapolis Power & Light Company, Louisville Gas and Electric Company, Northern Indiana Public Service Company, PSI Energy Inc. and Richmond Power and Light Company, as well as Indiana-Kentucky Electric Corporation (a subsidiary of Ohio Valley Electric Corporation, an affiliate that is not a member of the AEP System).

DIRECTORS

Karl G. Boyd (a)
Coulter R. Boyle, III
Gregory A. Clark
Peter J. DeMaria
William N. D'Onofrio
E. Linn Draper, Jr.
William J. Lhota
Gerald P. Maloney
James J. Markowsky
David B. Synowiec
Dale M. Trenary (b)
Joseph H. Vipperman
William E. Walters
Earl H. Wittkamper

OFFICERS

E. Linn Draper Jr.
Chairman of the Board and Chief Executive Officer

William J. Lhota
President and Chief Operating Officer

A. Alan Blind
Site Vice President, Donald C. Cook Nuclear Plant

Coulter R. Boyle, III
Vice President

Peter J. DeMaria
Vice President and Controller

Eugene E. Fitzpatrick
Vice President

Gerald P. Maloney
Vice President

James J. Markowsky
Vice President

Joseph H. Vipperman
Vice President

John F. DiLorenzo, Jr.
Secretary

Armando A. Pena
Treasurer

Elio Bafile
Assistant Controller and Assistant Secretary

Leonard V. Assante
Assistant Controller

Timothy P. Bowman
Assistant Controller

William L. Scott
Assistant Controller

John M. Adams, Jr.
Assistant Secretary

Maurice C. McIntyre
Assistant Secretary

John B. Shinnock
Assistant Secretary

Bruce M. Barber
Assistant Treasurer

Christopher J. Keklak
Assistant Treasurer

As of January 1, 1998 the current directors and officers of Indiana Michigan Power Company were employees of American Electric Power Service Corporation with eight exceptions: Messrs. Blind, Boyd, Boyle, Clark, McIntyre, Synowiec, Walters and Wittkamper, who were employees of Indiana Michigan Power Company.

(a) Elected April 1, 1997
(b) Resigned April 1, 1997

Selected Consolidated Financial Data

	Year Ended December 31,				
	1997	1996	1995 (in thousands)	1994	1993
INCOME STATEMENTS DATA:					
Operating Revenues	$1,391,917	$1,328,493	$1,283,157	$1,251,309	$1,202,643
Operating Expenses	1,184,129	1,108,076	1,077,434	1,029,340	992,485
Operating Income	207,788	220,417	205,723	221,969	210,158
Nonoperating Income (Loss)	4,415	2,729	6,272	7,428	(234)
Income Before Interest Charges	212,203	223,146	211,995	229,397	209,924
Interest Charges	65,463	65,993	70,903	71,895	80,580
Net Income	146,740	157,153	141,092	157,502	129,344
Preferred Stock Dividend Requirements	5,736	10,681	11,791	11,681	14,256
Earnings Applicable to Common Stock	$ 141,004	$ 146,472	$ 129,301	$ 145,821	$ 115,088

	December 31,				
	1997	1996	1995 (in thousands)	1994	1993
BALANCE SHEETS DATA:					
Electric Utility Plant	$4,514,497	$4,377,669	$4,319,564	$4,269,306	$4,290,957
Accumulated Depreciation and Amortization	1,973,937	1,861,893	1,751,965	1,659,940	1,714,829
Net Electric Utility Plant	$2,540,560	$2,515,776	$2,567,599	$2,609,366	$2,576,128
Total Assets	$3,967,798	$3,897,484	$3,928,337	$3,878,035	$3,723,648
Common Stock and Paid-in Capital	$ 789,056	$ 787,856	$ 787,686	$ 790,234	$ 790,625
Retained Earnings	278,814	269,071	235,107	216,658	177,638
Total Common Shareholder's Equity	$1,067,870	$1,056,927	$1,022,793	$1,006,892	$ 968,263
Cumulative Preferred Stock:					
Not Subject to Mandatory Redemption	$ 9,435	$ 21,977	$ 52,000	$ 52,000	$ 87,000
Subject to Mandatory Redemption (a)	68,445	135,000	135,000	135,000	100,000
Total Cumulative Preferred Stock	$ 77,880	$ 156,977	$ 187,000	$ 187,000	$ 187,000
Long-term Debt (a)	$1,049,237	$1,042,104	$1,040,101	$1,069,887	$1,073,154
Obligations Under Capital Leases (a)	$ 195,227	$ 130,965	$ 142,506	$ 152,589	$ 98,753
Total Capitalization and Liabilities	$3,967,798	$3,897,484	$3,928,337	$3,878,035	$3,723,648

(a) Including portion due within one year.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS AND FINANCIAL CONDITION

This report includes forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. These forward-looking statements reflect numerous assumptions, and involve a number of risks and uncertainties. Among the factors that could cause actual results to differ materially are: electric load and customer growth; abnormal weather conditions; available sources and cost of fuel and availability of generating capacity; the speed and degree to which competition enters the power generation, wholesale and retail sectors of the electric utility industry; state and federal regulatory initiatives that increase competition, threaten cost and investment recovery, and impact rate structures; the ability of the Company to successfully reduce its cost structure; the economic climate and growth in the service territory; inflationary trends and interest rates and other risks.

Business Outlook

The Company's ability to recover its costs as the industry transitions to competition and as customer choice is more broadly available is the most significant factor affecting its future. Competition in the wholesale generation market continues to intensify since the adoption of federal legislation in 1992 which gave wholesale customers the right to choose their energy supplier and the Federal Energy Regulatory Commission (FERC) orders issued in 1996 which force open access transmission. The introduction of competition and customer choice for retail customers has been slow although activity has been increasing. Federal legislation has been proposed to mandate competition and customer choice at the retail level, and several states have introduced or are considering similar legislation. The Michigan Commission has started a program for certain utilities to phase-in to competition with the objective of providing full customer choice by 2002. The Company has begun discussions with the Commission and other interested parties to formulate a plan. The actions by the Michigan commission were not mandated by legislation and are subject to a number of uncertainties and it is not possible to determine what impact if any the resolution of these matters will have on the operations of the Company. The Company's Michigan jurisdiction accounts for 12% of total revenues. Indiana is considering legislative initiatives to move to customer choice, although the timing is uncertain. The Company supports customer choice and is proactively involved in discussions at both the state and federal levels regarding how best to structure and transition to a competitive marketplace.

As the electric energy market evolves from cost-of-service ratemaking to market-based pricing, many complex issues must be resolved, including the recovery of stranded costs. While FERC orders No. 888 and 889 provide, under certain conditions, for recovery of stranded cost at the wholesale level, the issue of stranded cost recovery is unresolved at the much larger state retail level. The amount of any stranded costs the Company may experience depends on the timing and extent to which direct competition is introduced to our business and the then-existing market price of electricity.

Under the provisions of Statement of Financial Accounting Standards (SFAS) No. 71 "Accounting for the Effects of Certain Types of Regulation," regulatory assets (deferred expenses) and regulatory liabilities (deferred revenues) are included in the consolidated balance sheets of cost-based regulated utilities in accordance with regulatory actions to match expenses and revenues with cost-based rates. In order to maintain net regulatory assets (net expense deferrals) on the balance sheet, SFAS No. 71 requires that rates charged to customers be cost-based and the recovery of regulatory assets must be probable. In the event a portion of the Company's business no longer met the requirements of SFAS No. 71, net regulatory assets would have to be written off for that portion of the business. The provisions of SFAS No. 71 and SFAS No. 101 "Accounting for the Discontinuance of Application of Statement No. 71" never anticipated that deregulation would include an extended transition period or that it would provide for recovery after the transition period of stranded costs. In July 1997 the Emerging Issues Task Force (EITF) of the Financial Accounting Standards Board (FASB) reached a consensus that the application of SFAS No. 71 to a segment of a regulated electric utility which is subject to a legislative plan to transition

to competition in that segment should cease when the legislation is passed, or an enabling rate order is issued containing sufficient detail for the utility to reasonably determine what the plan would entail. The EITF indicated that the cessation of application of SFAS No. 71 would require that existing regulatory assets and impaired plant be written off unless they are recoverable.

Although FERC orders No. 888 and 889 provide for competition in the firm wholesale market, that market is a relatively small part of our business and most of our firm wholesale sales are still under cost-of-service contracts. As a result the Company's generation business is still cost-based regulated and should remain so for the near future pending the passage of enabling state legislation to deregulate the generation business. We believe that enabling state legislation should provide for the recovery of any generation-related net regulatory assets and other reasonable stranded costs from impaired generation assets. We are working with regulators, customers and legislators to provide for recovery of these stranded costs during a transition period in which rates are fixed or frozen and electric utilities would take steps to achieve cost savings which would be used to reduce or eliminate their stranded costs. However, if in the future the Company's generation business 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 of the Company would be adversely affected.

Cost Containment and Process Improvement

Efforts continue to reduce the cost of products and services in order to maintain our competitiveness. Prior to 1997, reviews of our major processes led to decisions to consolidate in the AEP Service Corporation senior management and certain functions and operations. While staff reductions and cost savings are presently being achieved from the consolidation and restructuring expenses for new marketing, customer services and modern efficient management information systems are increasing to prepare for competition.

In 1997, the Company began installing a new unified customer service system which is designed to support the request for service, billings, accounts receivable, credit and collection functions. The new unified customer service system replaces a 30-year-old customer system and a nine-year-old transmission and distribution work management system. Process improvement efforts and expenditures to develop and implement the new customer service system and similar efforts and expenditures to acquire, install and enhance new client server based accounting and budgeting/financial planning software should produce further improvements and efficiencies, enabling the Company to continue to offer its customers excellent service at competitive prices.

Nuclear Cost

Significant efforts have been made to enhance our competitive-ness in nuclear power generation and to improve our nuclear organizational efficiency. We continue to receive the "excellence in performance" award from the Institute of Nuclear Power Operations. Nuclear power plants have a major future financial commitment to safely dispose of spent nuclear fuel and radioactive plant components (i.e. to decommission the plant). It is difficult to reduce nuclear generation costs since certain major cost components are impacted by federal laws and Nuclear Regulatory Commission (NRC) regulations.

The Nuclear Waste Policy Act of 1982 established federal responsibility for the permanent off-site disposal of spent nuclear fuel and high-level radioactive waste. By law we participate in the Department of Energy's (DOE's) Spent Nuclear Fuel (SNF) disposal program which is described in Note 3 of the Notes to Consolidated Financial Statements. Since 1983 our customers have paid $272 million for the disposal of spent nuclear fuel consumed at the Cook Nuclear Plant. Under the provisions of the Nuclear Waste Policy Act, collections from customers are to provide the DOE with money to build a repository for spent fuel. To date the federal government has not made sufficient progress towards a permanent repository or otherwise assuming responsibility for SNF. As long as there is a delay in the construction of a government approved storage repository for SNF, the cost of both temporary and permanent storage will continue to increase. The cost to decommission the Cook Nuclear Plant is affected by both NRC regulations and the DOE's SNF disposal program. Studies completed in 1997 estimate the cost to decommission the Cook Nuclear Plant range from $700 million to $1.152 billion in 1997 dollars. This estimate could escalate due to uncertainty in the DOE's SNF disposal program and the length of time that SNF

may need to be stored at the plant site delaying decommissioning. Presently we are recovering the estimated cost of decommissioning the Cook Nuclear Plant over its remaining life. However, the Company's future results of operations, cash flows and possibly its financial condition could be adversely affected if the cost of spent nuclear fuel disposal and decommissioning continues to increase and cannot be recovered.

On September 9 and 10, 1997, during a NRC architect engineer design inspection, questions regarding the operability of certain safety systems caused Company operations personnel to shut down Units 1 and 2 of the Cook Nuclear Plant. On September 19, 1997, the NRC issued a Confirmatory Action Letter requiring the Company to address the issues identified in the letter. The Company is working with the NRC to resolve these issues and other issues related to restart of the units. Certain issues identified in the letter have been addressed. At this time management is unable to determine when the units will be returned to service. If the units are not returned to service in a reasonable period of time, it could have an adverse impact on results of operations, cash flows and possibly financial condition.

Environmental Concerns

We take great pride in our efforts to economically produce and deliver electricity while minimizing the impact on the environment. The Company has spent hundreds of millions of dollars to equip our facilities with the latest economical clean air and water technologies and to research possible new technologies. We intend to continue to take a leadership role to foster economically prudent efforts to protect and preserve the environment.

By-products from the generation of electricity include materials such as ash, slag, sludge, low-level radioactive waste and spent nuclear fuel. Coal combustion by-products are typically disposed of or treated in captive disposal facilities or are beneficially utilized. In addition, our generating plants and transmission and distribution facilities have used asbestos, polychlorinated biphenyls (PCBs) and other hazardous and nonhazardous materials. The Company is currently incurring costs to safely dispose of such substances. Additional costs could be incurred to comply with new laws and regulations if enacted.

The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA or Superfund) addresses clean-up of hazardous substances at disposal sites and authorized the United States Environmental Protection Agency (Federal EPA) to administer the clean-up programs. As of year-end 1997, the Company is currently involved in litigation with respect to two sites overseen by the Federal EPA, and has been named by the Federal EPA as a "Potentially Responsible Party" (PRP) for three other sites. There are four additional sites for which the Company has received information requests which could lead to PRP designation as well as information requests for one state administered site. The Company's liability has been resolved for a number of sites with no significant effect on results of operations and present estimates do not anticipate material cleanup costs for identified sites for which we have been declared a PRP. However, if for reasons not currently identified significant costs are incurred for cleanup, future results of operations, cash flows and possibly financial condition would be adversely affected unless the costs can be recovered.

In 1997 the Federal EPA published a revised ambient air quality standard for ozone and established a new ambient air quality standard for fine particulate matter. These standards are expected to result in redesignation of a number of areas of the country currently in compliance with the existing standard to nonattainment which could ultimately dictate more stringent emission restrictions for AEP generating units including those of the Company's. Under the new rules the states must first determine the attainment status of their areas. The states then have three years to submit a compliance plan and up to ten years after designation to come into compliance with the new standards. The compliance deadline could be as late as 2010 for the ozone standard and 2012-2015 for the fine particulate standard. Although we are reviewing the impact of the new rules, we are unable to estimate compliance costs without knowledge of the reductions that the states will find necessary to meet the new standards. If such reductions are significant and the Company and its affiliates must bear a significant portion of the cost of compliance in a region or county that is in violation of the revised standards, it would have a material adverse effect on results of operations, cash flows and possibly financial condition unless such costs are recovered from customers.

At the global climate conference in Kyoto, Japan in December 1997 more than 160 countries negotiated a treaty limiting emissions of greenhouse gases, chiefly carbon dioxide, which may eventually contribute to global warming. Although there is no clear scientific evidence that carbon dioxide contributes to global warming and damages the environment, the treaty, which requires Congressional approval, calls for a seven percent reduction below emission levels of greenhouse gases in 1990. We intend to work with the Congress to insure that science and reason are introduced to the debate. If approved by the Congress, the costs to comply with the emission reductions required by the Kyoto 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.

Results of Operations

Although operating revenues increased $63 million or 5% in 1997 due to increased accruals for retail power costs that will be collected in the future under power supply cost recovery mechanisms and increased wholesale transactions from a new power marketing business, net income decreased $10 million or 7% as a result of increases in purchased power and other operation expenses. In July 1997 the Company started a new power marketing business of buying and selling power outside the AEP System which accounted for the increases in purchased power and wholesale revenues. The increase in other operation expense reflects the effect of the recognition of gains on sales of emission allowance in 1996 and higher administrative and general costs and uncollectible accounts expenses in 1997. In 1996 net income increased $16 million or 11% mainly due to increased wholesale sales, a reduction in maintenance expense and reduced financing costs. Also contributing to the earnings increase in 1996 were severance pay charges recorded in 1995 in connection with AEP's restructuring of management and operations and gains recorded in 1996 from emission allowance transactions.

Operating Revenues Increase

Operating revenues increased 4.8% in 1997 following a 3.5% increase in 1996. The following analyzes the changes in operating revenues:

	Increase (Decrease) From Previous Year			
(dollars in millions)	1997		1996	
	Amount	%	Amount	%
Retail:				
Price Variance	$ 26.6		$(25.9)	
Volume Variance	7.4		32.8	
	34.0	3.7	6.9	0.8
Wholesale:				
Price Variance	43.8		(55.6)	
Volume Variance	(20.2)		89.6	
	23.6	6.0	34.0	9.5
Other Operating Revenues	5.8		4.4	
Total	$ 63.4	4.8	$ 45.3	3.5

The increase in operating revenues in 1997 can be attributed to increased retail and wholesale revenues. The increase in retail revenues results from the accrual of revenues to be recovered from ratepayers for the increased cost of replacement power and increased fossil fuel usage during an outage of both units at the Company's nuclear plant. Under the retail jurisdictional fuel clauses, revenues are accrued for the unrecovered cost of fuel in both retail jurisdictions and for replacement power costs in the Michigan jurisdiction until approved for billing. The increase in wholesale revenues in 1997 was mainly due to the introduction of new power marketing transactions in July 1997. The new power marketing transactions involve the purchase and sale of electricity outside the AEP transmission system. The increase in power marketing sales was offset by a decrease in sales to the Power Pool due mainly to the outage of Cook Plant. The reduction in sales to the Power Pool did not lead to a corresponding decrease in revenues since capacity credits continue to be received. Capacity credits are designed to allocate the cost of the AEP System's generating capacity among the members of the Power Pool based on the Power Pool members relative peak demands and generating reserves. The Company is compensated for the out-of-pocket costs of energy delivered to the Power Pool.

Operating revenues increased in 1996 primarily as a result of increased wholesale sales attributable to increased internal generation being supplied to the Power Pool and unaffiliated utilities. The Company's share of Power Pool allocated sales increased 40% due to increased transactions with other utilities and power marketers. During 1996 the Company provided coal conversion services to power marketers and unaffiliated utilities resulting in 1.2 billion kilowatthours of electricity being generated under a new FERC-approved interruptible tariff for the conversion of customers' coal to electricity and does not include any fuel cost. Since these sales are for the service of converting the customers' coal to electricity and do not include any fuel cost, the average wholesale price per kilowatthour was significantly less in 1996 than in 1995.

Operating Expenses Increase

Total operating expenses increased 7% in 1997 primarily due to an increase in power purchases. The 3% increase in 1996 was mainly due to the increased operation of the Company's nuclear units, increased Power Pool wholesale transactions, and higher income taxes partially offset by a significant reduction in maintenance expense. The changes in operating expenses were:

(dollars in millions)	Increase (Decrease) From Previous Year 1997 Amount	1997 %	1996 Amount	1996 %
Fuel	$(9.8)	(4.2)	$ 13.3	6.0
Purchased Power	78.8	56.8	13.3	10.6
Other Operation	23.6	7.6	3.5	1.2
Maintenance	2.5	2.2	(26.5)	(18.7)
Depreciation and Amortization	0.4	0.3	1.6	1.2
Amortization of Rockport Plant Unit 1 Phase-in Plan Deferrals	(3.8)	(24.1)	-	-
Taxes Other Than Federal Income Taxes	(8.8)	(11.9)	1.9	2.7
Federal Income Taxes	(6.8)	(8.8)	23.5	43.5
Total	$76.1	6.9	$ 30.6	2.8

The decrease in fuel expense in 1997 reflects a 36% decrease in nuclear generation as both nuclear units were unavailable from September 9 through the end of the year. See Cook Plant shutdown discussed above. The decrease in nuclear generation was partially offset by a 6% increase in fossil generation. Fuel expense increased in 1996 due to a 17% increase in nuclear generation made possible by the shorter refueling outage in 1996 versus an extended refueling and maintenance outage in 1995. This increase was partially offset by a lower average price per ton of coal consumed from a favorable settlement of a coal transportation dispute.

Purchased power expense increased significantly in 1997 due to the Company's share of purchases of power by AEP's new power marketing business and increased purchases from the Power Pool to replace power usually generated by the out-of-service nuclear units. The rise in purchased power expense in 1996 was mainly due to additional power purchases under an agreement with the Ohio Valley Electric Corporation, an affiliated company which is not a member of the Power Pool, and increased purchases from the Power Pool to support the Company's allocated share of higher Power Pool wholesale transactions with non-affiliated utilities.

Other operation expense increased in 1997 due to the effect of gains on the disposition of emission allowances recorded in 1996 and higher administrative and general costs and uncollectible accounts receivable expenses.

The substantial decrease in maintenance expense in 1996 was due to cost-reduction measures at the Company's nuclear plant, which reduced the number of employees performing maintenance and lowered payments for contract maintenance labor.

The recovery period for Rockport Plant Unit 1 costs deferred under a rate phase-in plan in the Indiana jurisdiction ended in August 1997 causing the decrease in the amortization of phase-in plan deferrals. The deferred costs were amortized over a 10-year period commensurate with their collection from customers pursuant to an order of the Indiana Utility Regulatory Commission (IURC).

The decrease in taxes other than federal income taxes in 1997 was due to decreases in real and personal property taxes, Michigan single business tax and Indiana supplemental income tax.

Federal income taxes attributable to operations decreased in 1997 due to a decrease in pre-tax operating income. The increase in 1996 reflects an increase in pre-tax operating income and changes in certain book/tax differences accounted for on a flow-through basis for rate-making purposes.

Financing Costs

The decline in interest charges in 1996 was due to debt repayments and a refinancing program which lowered interest rates.

Financial Condition

In 1997 the Company maintained its strong financial condition. We redeemed 790,967 shares of cumulative preferred stock with rates ranging from 4.12% to 6.875% at a total cost of $79 million. We used short-term debt and junior subordinated deferrable interest debentures to pay for the preferred stock tendered and to benefit from the tax deductibility of interest.

The Company issued $48 million principal amount of long-term obligations in 1997 at 6.4%. We continued to reduce financing costs by retiring higher-cost bonds and restructuring the long-term debt from senior secured/first mortgage bonds to senior unsecured debt and junior debentures. The principal amount of long-term debt retirements, including maturities, totaled $50 million at 8.75%. Our senior secured debt/first mortgage bond ratings which were reaffirmed and improved in 1997, are: Moody's, Baa1; Standard & Poor's, A-; and Fitch, BBB+.

Gross plant and property additions were $235 million in 1997 and $144 million in 1996. Management estimates construction expenditures for the next three years to be $456 million which includes the replacement of the Cook Plant Unit 1 steam generators. The funds for construction of new facilities and improvement of existing facilities can come from a combination of internally generated funds, short-term and long-term borrowings, preferred stock issuances and investments in common equity by the Company's parent, American Electric Power Company, Inc. (AEP Co., Inc.). However, all of the construction expenditures for the next three years are expected to be financed with internally generated funds. Inflation affects the Company's cost of replacing utility plant and the cost of operating and maintaining plant. The rate-making process generally limits our 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.

When necessary the Company generally issues short-term debt to provide for interim financing of capital expenditures that exceed internally generated funds. At December 31, 1997, $442 million of unused short-term lines of credit shared with other AEP System companies were available. Short-term debt borrowings are limited by provisions of the Public Utility Holding Company Act of 1935 to $175 million. Generally periodic reductions of outstanding short-term debt are made through issuances of long-term debt and through additional capital contributions by the parent company.

The Company's earnings coverage presently exceeds all minimum coverage requirements for the issuance of mortgage bonds and preferred stock. The minimum coverage ratios are 2.0 for mortgage bonds and 1.5 for preferred stock. At December 31, 1997, the mortgage bonds and preferred stock coverage ratios were 7.57 and 2.88, respectively.

The Company is committed under unit power agreements to purchase 70% of an affiliated (AEGCo's) share of the 1,300 mw Rockport Plant capacity unless it is sold to other utilities. AEGCo has a long contract with an unaffiliated utility for 455 mw that expires in 1999. AEGCo's total revenues from this contract in 1997 were $72 million including capacity and energy charges.

Other Matters

Corporate Owned Life Insurance

In connection with the audit of AEP's consolidated federal income tax returns the Internal Revenue Service (IRS) agents sought a ruling from the IRS National Office that certain interest deductions relating to a corporate owned life insurance (COLI) program should not be allowed. The Company established the COLI program in 1990 as part of its strategy to fund and reduce the cost of medical benefits for retired employees. AEP filed a brief with the IRS National Office refuting the agents' position. No adjustments have been proposed by the IRS. However, should a disallowance of COLI interest deductions be proposed it would, if sustained, reduce earnings by approximately $59 million (including interest). Management believes it has meritorious defenses and will vigorously contest any proposed adjustments. No provisions for this amount have been recorded. In the event the

Company is unsuccessful it could have a material adverse impact on results of operations and cash flows.

Computer Software - Year 2000 Compliance

Many existing computer hardware and software programs will not properly recognize calendar dates beginning in the year 2000. Unless corrected, this "Year 2000" problem may cause computer malfunctions, such as system shutdowns or incorrect calculations and system output. The Company is addressing the problem internally by modifying or replacing its computer hardware and software programs. The problem is also being addressed externally with entities that interact electronically with the Company, including but not limited to, suppliers, service providers, government agencies, customers, creditors and financial service organizations. However, due to the complexity of the problem and the interdependent nature of computer systems, if the Company's corrective actions, and/or the actions of other interdependent entities, fail for critical applications, the Company may be adversely impacted in the year 2000. Although significant, the cost of correcting the "Year 2000" problem is not expected to have a material impact on results of operations, cash flows or financial condition.

New Accounting Standards

In June 1997 the FASB issued SFAS 130 "Reporting Comprehensive Income" and SFAS 131 "Disclosures About Segments of an Enterprise and Related Information." SFAS 130 establishes the standards for reporting and displaying components of "comprehensive income," which is the total of net income and all other changes in equity except those resulting from investments by shareholders and dispositions to shareholders. SFAS 131 initiates standards for reporting information about operating segments in annual and interim financial statements as well as related disclosures about products and services, geographic areas and major customers. I&M's adoption of these new reporting standards in 1998 is not expected to have a material effect on the results of operations, cash flows and/or financial condition.

Litigation

The Company is involved in a number of legal proceedings and claims. While we are 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 and/or financial condition.

Consolidated Statements of Income

	Year Ended December 31,		
	1997	1996 (in thousands)	1995
OPERATING REVENUES	$1,391,917	$1,328,493	$1,283,157
OPERATING EXPENSES:			
Fuel	226,402	236,237	222,967
Purchased Power	217,460	138,687	125,413
Other Operation	334,115	310,513	306,967
Maintenance	117,780	115,300	141,813
Depreciation and Amortization	140,812	140,437	138,814
Amortization of Rockport Plant Unit 1 Phase-in Plan Deferrals	11,871	15,644	15,644
Taxes Other Than Federal Income Taxes	64,945	73,729	71,791
Federal Income Taxes	70,744	77,529	54,025
Total Operating Expenses	1,184,129	1,108,076	1,077,434
OPERATING INCOME	207,788	220,417	205,723
NONOPERATING INCOME	4,415	2,729	6,272
INCOME BEFORE INTEREST CHARGES	212,203	223,146	211,995
INTEREST CHARGES	65,463	65,993	70,903
NET INCOME	146,740	157,153	141,092
PREFERRED STOCK DIVIDEND REQUIREMENTS	5,736	10,681	11,791
EARNINGS APPLICABLE TO COMMON STOCK	$ 141,004	$ 146,472	$ 129,301

See Notes to Consolidated Financial Statements.

Consolidated Statements of Cash Flows

	Year Ended December 31,		
	1997	1996	1995
		(in thousands)	
OPERATING ACTIVITIES:			
Net Income	$ 146,740	$ 157,153	$ 141,092
Adjustments for Noncash Items:			
Depreciation and Amortization	148,630	148,123	148,441
Amortization of Rockport Plant Unit 1 Phase-in Plan Deferrals	11,871	15,644	15,644
Amortization (Deferral) of Incremental Nuclear Refueling Outage Expenses (net)	(15,967)	7,662	8,684
Deferred Federal Income Taxes	3,922	(24,687)	(23,564)
Deferred Investment Tax Credits	(8,428)	(8,729)	(9,004)
Changes in Certain Current Assets and Liabilities:			
Accounts Receivable (net)	(10,456)	(10,235)	4,121
Fuel, Materials and Supplies	5,168	903	(6,255)
Accrued Utility Revenues	7,774	5,642	(3,355)
Accounts Payable	6,502	1,186	(2,431)
Taxes Accrued	(18,550)	(6,296)	8,075
Other (net)	(16,995)	7,975	(23,099)
Net Cash Flows From Operating Activities	260,211	294,341	258,349
INVESTING ACTIVITIES:			
Construction Expenditures	(122,360)	(95,046)	(117,785)
Long-term Receivable from Customer for Construction of Facilities	-	62	(18,733)
Proceeds from Sales of Property and Other	2,016	2,714	9,325
Net Cash Flows Used For Investing Activities	(120,344)	(92,270)	(127,193)
FINANCING ACTIVITIES:			
Issuance of Long-term Debt	47,728	38,579	96,819
Retirement of Cumulative Preferred Stock	(78,877)	(30,568)	-
Retirement of Long-term Debt	(50,000)	(46,091)	(141,122)
Change in Short-term Debt (net)	76,100	(46,475)	39,375
Dividends Paid on Common Stock	(131,260)	(112,508)	(110,852)
Dividends Paid on Cumulative Preferred Stock	(5,931)	(10,498)	(11,560)
Net Cash Flows Used For Financing Activities	(142,240)	(207,561)	(127,340)
Net Increase (Decrease) in Cash and Cash Equivalents	(2,373)	(5,490)	3,816
Cash and Cash Equivalents January 1	8,233	13,723	9,907
Cash and Cash Equivalents December 31	$ 5,860	$ 8,233	$ 13,723

See Notes to Consolidated Financial Statements.

Consolidated Balance Sheets

	December 31, 1997	December 31, 1996
	(in thousands)	
ASSETS		
ELECTRIC UTILITY PLANT:		
Production	$2,545,484	$2,525,969
Transmission	908,736	881,407
Distribution	737,902	696,069
General (including nuclear fuel)	233,888	189,619
Construction Work in Progress	88,487	84,605
Total Electric Utility Plant	4,514,497	4,377,669
Accumulated Depreciation and Amortization	1,973,937	1,861,893
NET ELECTRIC UTILITY PLANT	2,540,560	2,515,776
NUCLEAR DECOMMISSIONING AND SPENT NUCLEAR FUEL DISPOSAL TRUST FUNDS	566,390	490,778
OTHER PROPERTY AND INVESTMENTS	156,228	154,265
CURRENT ASSETS:		
Cash and Cash Equivalents	5,860	8,233
Accounts Receivable:		
Customers	107,087	90,656
Affiliated Companies	15,662	13,727
Miscellaneous	14,561	21,439
Allowance for Uncollectible Accounts	(1,188)	(156)
Fuel - at average cost	17,182	23,977
Materials and Supplies - at average cost	78,701	77,074
Accrued Utility Revenues	30,521	38,295
Prepayments	4,685	10,271
TOTAL CURRENT ASSETS	273,071	283,516
REGULATORY ASSETS	400,489	421,692
DEFERRED CHARGES	31,060	31,457
TOTAL	$3,967,798	$3,897,484

See Notes to Consolidated Financial Statements.

	December 31, 1997	December 31, 1996
	(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	732,472	731,272
Retained Earnings	278,814	269,071
Total Common Shareholder's Equity	1,067,870	1,056,927
Cumulative Preferred Stock:		
Not Subject to Mandatory Redemption	9,435	21,977
Subject to Mandatory Redemption	68,445	135,000
Long-term Debt	1,014,237	1,042,104
TOTAL CAPITALIZATION	2,159,987	2,256,008
OTHER NONCURRENT LIABILITIES:		
Nuclear Decommissioning	381,016	313,845
Other	232,667	174,903
TOTAL OTHER NONCURRENT LIABILITIES	613,683	488,748
CURRENT LIABILITIES:		
Long-term Debt Due Within One Year	35,000	-
Short-term Debt	119,600	43,500
Accounts Payable - General	36,729	31,015
Accounts Payable - Affiliated Companies	31,665	30,877
Taxes Accrued	46,850	65,400
Interest Accrued	15,741	15,281
Obligations Under Capital Leases	34,033	29,740
Other	63,250	66,436
TOTAL CURRENT LIABILITIES	382,868	282,249
DEFERRED INCOME TAXES	559,708	594,879
DEFERRED INVESTMENT TAX CREDITS	138,045	146,473
DEFERRED GAIN ON SALE AND LEASEBACK - ROCKPORT PLANT UNIT 2	92,419	96,125
DEFERRED CREDITS	21,088	33,002
COMMITMENTS AND CONTINGENCIES (Note 3)		
TOTAL	$3,967,798	$3,897,484

See Notes to Consolidated Financial Statements.

Consolidated Statements of Retained Earnings

	Year Ended December 31,		
	1997	1996 (in thousands)	1995
Retained Earnings January 1	$269,071	$235,107	$216,658
Net Income	146,740	157,153	141,092
	415,811	392,260	357,750
Deductions:			
Cash Dividends Declared:			
Common Stock	131,260	112,508	110,852
Cumulative Preferred Stock:			
4-1/8% Series	249	495	495
4.56% Series	88	273	273
4.12% Series	80	165	165
5.90% Series	985	2,360	2,360
6-1/4% Series	1,266	1,875	1,875
6.30% Series	834	2,205	2,205
6-7/8% Series	1,255	2,063	2,063
7.08% Series	-	531	2,124
Total Cash Dividends Declared	136,017	122,475	122,412
Capital Stock Expense	980	714	231
Total Deductions	136,997	123,189	122,643
Retained Earnings December 31	$278,814	$269,071	$235,107

See Notes to Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SIGNIFICANT ACCOUNTING POLICIES:

Organization

Indiana Michigan Power Company (the Company or I&M) is a wholly-owned subsidiary of American Electric Power Company, Inc. (AEP Co., Inc.), a public utility holding company. The Company is engaged in the generation, sale, purchase, transmission and distribution of electric power to 549,000 retail customers in its service territory in northern and eastern Indiana and a portion of southwestern Michigan. Wholesale electric power is supplied to neighboring utility systems, power marketers and the American Electric Power (AEP) System Power Pool (Power Pool). As a member of the AEP Power Pool and a signatory company to the American Electric Power System (AEP System) Transmission Equalization Agreement, its facilities are operated in conjunction with the facilities of certain other AEP affiliated utilities as an integrated utility system.

The Company has two wholly-owned subsidiaries, that were formerly engaged in coal-mining operations which are consolidated in these financial statements, Blackhawk Coal Company and Price River Coal Company. Blackhawk Coal Company currently leases and subleases portions of its Utah coal rights, land and related mining equipment to unaffiliated companies. Price River Coal Company, which owns no land or mineral rights, is inactive.

Regulation

As a subsidiary of AEP Co., Inc., I&M is subject to regulation by the Securities and Exchange Commission (SEC) under the Public Utility Holding Company Act of 1935 (1935 Act). Retail rates are regulated by the Indiana Utility Regulatory Commission (IURC) and the Michigan Public Service Commission (MPSC). The Federal Energy Regulatory Commission (FERC) regulates wholesale rates.

Principles of Consolidation

The consolidated financial statements include I&M and its wholly-owned subsidiaries. Significant intercompany items are eliminated in consolidation.

Basis of Accounting

As a cost-based rate-regulated entity, I&M's financial statements reflect the actions of regulators that result in the recognition of revenues and expenses in different time periods than enterprises that are not cost-based rate-regulated. In accordance with Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation," regulatory assets (deferred expenses) and regulatory liabilities (deferred income) are recorded to reflect the economic effects of regulation and to match expenses with regulated revenues.

Use of Estimates

The preparation of these financial statements in conformity with generally accepted accounting principles requires in certain instances the use of estimates. Actual results could differ from those estimates.

Utility Plant

Electric utility plant is stated at original cost and is generally subject to first mortgage liens. Additions, major replacements and betterments are added to the plant accounts. Retirements of plant are deducted from the electric plant in service account and deducted from accumulated depreciation together with associated removal costs, net of salvage.

The costs of labor, materials and overheads incurred to operate and maintain utility 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 utility plant. It represents the estimated cost of borrowed and equity funds used to finance construction projects. The amounts of AFUDC for 1997, 1996 and 1995 were not significant.

Depreciation and Amortization

Depreciation of electric utility plant is provided on a straight-line basis over the estimated useful lives of utility plant and is calculated largely through the use of composite rates by functional class as follows:

Functional Class of Property	Annual Composite Depreciation Rates
Production:	
Steam-Nuclear	3.4%
Steam-Fossil-Fired	4.4%
Hydroelectric-Conventional	3.2%
Transmission	1.9%
Distribution	4.2%
General	3.8%

Amounts for the demolition and removal of non-nuclear plant are presently recovered through depreciation charges included in rates. The accounting and rate-making treatment afforded nuclear decommissioning costs and nuclear fuel disposal costs are discussed in Note 3.

Cash and Cash Equivalents

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

Operating Revenues and Fuel Costs

Revenues include the accrual of electricity consumed but unbilled at month-end as well as billed revenues. Fuel costs are matched with revenues in accordance with rate commission orders. Revenues are accrued related to unrecovered fuel in both retail jurisdictions and for replacement power costs in the Michigan jurisdiction until approved for billing. If the Company's earnings exceed the allowed return in the Indiana jurisdiction, the fuel clause mechanism provides for the refunding of the excess earnings to ratepayers. Wholesale jurisdictional fuel cost changes are expensed and billed as incurred.

Levelization of Nuclear Refueling Outage Costs

Incremental operation and maintenance costs associated with refueling outages at the Donald C. Cook Nuclear Plant (Cook Plant) are deferred commensurate with their rate-making treatment and amortized over the period (generally eighteen months) beginning with the commencement of an outage and ending with the beginning of the next outage.

Income Taxes

The Company follows the liability method of accounting for income taxes as prescribed by SFAS No. 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 rates, deferred income taxes are provided with related regulatory assets and liabilities in accordance with SFAS No. 71.

Investment Tax Credits

Based on directives of regulatory commissions, the Company reflected investment tax credits in rates and on its books on a deferral basis. Commensurate with rate treatment deferred investment tax credits are being amortized over the life of the related plant investment. The Company's policy with regard to investment tax credits for nonutility property is to practice the flow-through method of accounting.

Debt and Preferred Stock

Gains and losses on reacquistion of debt are deferred and amortized over the remaining term of the reacquired debt in accordance with rate-making treatment. If the debt is refinanced the reacquisition costs are deferred and amortized over the term of the replacement debt commensurate with their recovery in rates.

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

Redemption premiums paid to reacquire preferred stock are included in paid-in capital and amortized to reduce retained earnings commensurate with their recovery in rates. The excess of par value over the cost of preferred stock reacquired is credited to paid-in capital and amortized to retained earnings.

Nuclear Decommissioning and Spent Nuclear Fuel Disposal Trust Funds

Securities held in trust funds for decommissioning nuclear facilities and for the disposal of spent nuclear fuel are recorded at market value in accordance with SFAS No. 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. Due to the rate-making process, adjustments for unrealized gains and losses 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.

Other Property and Investments

Other property and investments are stated at cost.

2. EFFECTS OF REGULATION AND PHASE-IN PLANS:

In accordance with SFAS No. 71 the consolidated financial statements include regulatory assets (deferred expenses) and regulatory liabilities (deferred income) recorded in accordance with regulatory actions in order to match expenses and revenues from cost-based rates. 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 No. 71 requires that the Company's rates be cost-based regulated. The Company has reviewed all the evidence currently available and concluded that it continues to meet the requirements to apply SFAS No. 71. In the event a portion of the Company's business were to no longer meet those requirements, net regulatory assets would have to be written off for that portion of the business and assets attributable to that portion of the business would have to be tested for possible impairment and if required an impairment loss recorded unless the net regulatory assets and impairment losses are recoverable as a stranded investment.

Recognized regulatory assets and liabilities are comprised of the following:

	December 31,	
	1997	1996
	(in thousands)	
Regulatory Assets:		
Amounts Due From Customers for Future Income Taxes	$277,966	$317,059
Department of Energy Decontamination and Decommissioning Assessment	42,648	45,994
Rate Phase-in Plan Deferrals	-	11,871
Nuclear Refueling Outage Cost Levelization	31,772	15,805
Unamortized Loss On Reacquired Debt	17,210	19,388
Other	30,893	11,575
Total Regulatory Assets	$400,489	$421,692
Regulatory Liabilities:		
Deferred Investment Tax Credits	$138,045	$146,473
Other*	1,262	16
Total Regulatory Liabilities	$139,307	$146,489

* Included in Deferred Credits on Consolidated Balance Sheets.

The Rockport Plant consists of two 1,300 megawatt (mw) coal-fired units. I&M and AEP Generating Company (AEGCo), an affiliate, each own 50% of one unit (Rockport 1) and each lease a 50% interest in the other unit (Rockport 2) from unaffiliated lessors under an operating lease. The gain on the sale and leaseback of Rockport 2 was deferred and is being amortized, with related taxes, over the initial lease term which expires in 2022.

Rate phase-in plans in the Company's Indiana and FERC jurisdictions provided for the recovery and straight-line amortization of deferred Rockport Plant Unit 1 costs over ten years beginning in 1987. In 1997 the amortization and recovery of the deferred Rockport Plant Unit 1 Phase-in Plan costs was completed. During the recovery period net income was unaffected by the recovery of the phase-in deferrals. Amortization was $11.9 million in 1997 and $15.6 million in 1996 and 1995.

3. COMMITMENTS AND CONTINGENCIES:

Construction and Other Commitments

Substantial construction commitments have been made to support the Company's utility operations including the replacement of the Cook

Plant Unit 1 steam generators. Such commitments do not include any expenditures for new generating capacity. Aggregate construction program expenditures for 1998-2000 are estimated to be $456 million.

Long-term fuel supply contracts contain clauses that provide for periodic price adjustments. The retail jurisdictions have fuel clause mechanisms that provide for recovery of changes in the cost of fuel with the regulators' review and approval. The contracts are for various terms, the longest of which extends to 2014, and contain various clauses that would release the Company from its obligation under certain force majeure conditions.

The Company is committed under unit power agreements to purchase 70% of an affiliate's (AEGCo's) share of the 1,300 mw Rockport Plant capacity unless it is sold to unaffiliated utilities. AEGCo has one long-term contract with an unaffiliated utility that expires in 1999 for 455 mw of Rockport Plant capacity.

The Company sells under contract up to 250 mw of its Rockport Plant capacity to an unaffiliated utility. The contract expires in 2009.

Revised Air Quality Standards

On July 18, 1997, the United States Environmental Protection Agency published a revised National Ambient Air Quality Standard (NAAQS) for ozone and a new NAAQS for fine particulate matter (less than 2.5 microns in size). The new ozone standard is expected to result in redesignation of a number of areas of the country that are currently in compliance with the existing standard to nonattainment status which could ultimately dictate more stringent emission restrictions for AEP System generating units. New stringent emission restrictions on AEP System generating units to achieve attainment of the fine particulate matter standard could also be imposed. The AEP System operating companies joined with other utilities to appeal the revised NAAQS and filed petitions for review in August and September 1997 in the U.S. Court of Appeals for the District of Columbia Circuit. Management is unable to estimate compliance costs without knowledge of the reductions that may be necessary to meet the new standards. If such costs are significant, they could have a material adverse effect on results of operations, cash flows and possibly financial condition unless recovered.

Litigation

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

Nuclear Plant

I&M owns and operates the two-unit 2,110 mw Donald C. Cook Nuclear Plant under licenses granted by the Nuclear Regulatory Commission. 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 United States, the resultant liability could be substantial. By agreement I&M is partially liable together with all other electric utility companies that own nuclear generating units for a nuclear power plant incident. In the event nuclear losses or liabilities are underinsured or exceed accumulated funds and recovery is not possible, results of operations, cash flows and financial condition would be negatively affected.

Nuclear Plant Shutdown

On September 9 and 10, 1997, during a Nuclear Regulatory Commission (NRC) architect engineer design inspection, questions regarding the operability of certain safety systems caused Company operations personnel to shut down Units 1 and 2 of the Cook Nuclear Plant. On September 19, 1997, the NRC issued a Confirmatory Action Letter requiring the Company to address the issues identified in the letter. The Company is working with the NRC to resolve these issues and other issues related to restart of the units. Certain issues identified in the letter have been addressed. At this time management is unable to determine when the units will be returned to service. If the units are not returned to service in a timely manner, it could have an adverse impact on results of operations, cash flows and possibly financial condition.

Nuclear Incident Liability

Public liability is limited by law to $8.9 billion should an incident occur at any licensed reactor in the United States. Commercially available insurance provides $200 million of coverage. In

the event of a nuclear incident at any nuclear plant in the United States the remainder of the liability would be provided by a deferred premium assessment of $79.3 million on each licensed reactor payable in annual installments of $10 million. As a result, I&M could be assessed $158.6 million per nuclear incident payable in annual installments of $20 million. The number of incidents for which payments could be required is not limited.

Nuclear insurance pools and other insurance policies provide $3.6 billion (reduced to $3.0 billion effective January 1, 1998) of property damage, decommissioning and decontamination coverage for Cook Plant. Additional insurance provides coverage for extra costs resulting from a prolonged accidental Cook Plant outage. Some of the policies have deferred premium provisions which could be triggered by losses in excess of the insurer's resources. The losses could result from claims at the Cook Plant or certain other non-affiliated nuclear units. The Company could be assessed up to $35.8 million annually under these policies.

Spent Nuclear Fuel Disposal

Federal law provides for government responsibility for permanent spent nuclear fuel disposal and assesses nuclear plant owners fees for spent fuel disposal. A fee of one mill per kilowatthour for fuel consumed after April 6, 1983 is being collected from customers and remitted to the U.S. Treasury. Fees and related interest of $181 million for fuel consumed prior to April 7, 1983 have been recorded as long-term debt. I&M has not paid the government the pre-April 1983 fees due to continued delays and uncertainties related to the federal disposal program. At December 31, 1997, funds collected from customers towards the pre-April 1983 fee and related earnings thereon approximate the liability.

Decommissioning and Low Level Waste Accumulation Disposal

Decommissioning costs are accrued over the service life of the Cook Plant. The licenses to operate the two nuclear units expire in 2014 and 2017. After expiration of the licenses the plant is expected to be decommissioned through dismantlement. A 1997 nuclear decommissioning study has been completed. The estimated cost of decommissioning and low level waste accumulation disposal costs ranges from $700 million to $1,152 million in 1997 nondiscounted dollars. The wide range is caused by variables in assumptions including the estimated length of time spent nuclear fuel must be stored at the plant subsequent to ceasing operations. This in turn depends on future developments in the federal government's spent nuclear fuel disposal program. Continued delays in the federal fuel disposal program can result in increased decommissioning costs. The Company is recovering estimated 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 Company records decommissioning costs in other operation expense and records a noncurrent liability equal to the decommissioning cost recovered in rates; such amount was $28 million in 1997, $27 million in 1996 and $30 million in 1995 including $4 million of special deposits. Decommissioning costs recovered from customers are deposited in external trusts. Trust fund earnings increase the fund assets and the recorded liability thereby decreasing the amount needed to be recovered from ratepayers. At December 31, 1997 the Company has recognized a decommissioning liability of $381 million.

4. RELATED PARTY TRANSACTIONS:

Benefits and costs of the AEP System's generating plants are shared by members of the Power Pool. The Company is a member of the Power Pool. Under the terms of the AEP System Interconnection Agreement, capacity charges and credits are designed to allocate the cost of the AEP System's capacity among the Power Pool members based on their relative peak demands and generating reserves. Power Pool members are also compensated for the out-of-pocket costs of energy delivered to the Power Pool and charged for energy received from the Power Pool. The Company is a net supplier to the pool and, therefore, receives capacity credits from the Power Pool.

Operating revenues include revenues for capacity and energy supplied to the Power Pool as follows:

	Year Ended December 31,		
	1997	1996	1995
		(in thousands)	
Capacity Revenues	$ 53,282	$ 57,594	$ 59,918
Energy Revenues	64,861	98,162	83,799
Total	$118,143	$155,756	$143,717

Purchased power expense includes charges of $51.0 million in 1997, $34.5 million in 1996 and $25.4 million in 1995 for energy received from the Power Pool.

Power Pool members share in wholesale sales to unaffiliated entities made by the Power Pool. The Company's share of the wholesale power pool sales included in operating revenues were $127.4 million in 1997, $73.4 million in 1996 and $52.6 million in 1995.

In addition, the Power Pool purchases power from unaffiliated entities for resale to other unaffiliated entities. The Company's share of these purchases was included in purchased power expense and totaled $67.9 million (including new power marketing transactions) in 1997, $8.1 million in 1996 and $10.7 million in 1995. Revenues from these transactions, including a transmission fee for power that passes through the AEP System transmission network, are included in the above Power Pool wholesale operating revenues.

The cost of Rockport Plant power purchased from AEGCo, an affiliated company that is not a member of the Power Pool, was included in purchased power expense in the amounts of $87.5 million, $85.4 million and $85.2 million in 1997, 1996 and 1995, respectively.

The cost of power purchased from Ohio Valley Electric Corporation, an affiliated but non-associated company that is not a member of the Power Pool, was included in purchased power expense in the amounts of $11.0 million, $10.7 million and $4.0 million in 1997, 1996 and 1995, respectively.

The Company operates the Rockport Plant and bills AEGCo for its share of operating costs.

AEP System companies participate in a transmission equalization agreement. This agreement combines certain AEP System companies' investments in transmission facilities and shares the costs of ownership in proportion to the AEP System companies' respective peak demands. Pursuant to the terms of the agreement, since the Company's relative investment in transmission facilities is greater than its relative peak demand, other operation expense includes equalization credits of $46.1 million, $46.3 million and $46.7 million in 1997, 1996 and 1995, respectively.

Revenues from providing barging services were recorded in nonoperating income as follows:

	Year Ended December 31,		
	1997	1996	1995
		(in thousands)	
Affiliated Companies	$24,427	$22,740	$23,160
Unaffiliated Companies	8,383	6,776	6,992
Total	$32,810	$29,516	$30,152

American Electric Power Service Corporation (AEPSC) provides certain managerial and professional services to AEP System companies. The costs of the services are billed by AEPSC on a direct-charge basis to the extent practicable and on reasonable bases of proration for indirect costs. The charges 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.

5. BENEFIT PLANS:

The Company and its subsidiaries participate in the AEP System pension plan, a trusteed, noncontributory defined benefit plan covering all employees meeting eligibility requirements. Benefits are based on service years and compensation levels. Pension costs are allocated by first charging each System company with its service cost and then allocating the remaining pension cost in proportion to its share of the projected benefit obligation. The funding policy is to make annual trust fund contributions equal to the net periodic pension cost up to the maximum amount deductible for federal income taxes, but not less than the minimum required contribution in accordance with the Employee Retirement Income Security Act of 1974. Net pension costs for the years ended December 31, 1997, 1996 and 1995 were $2.1 million, $4.1 million and $2.7 million, respectively.

Postretirement benefits other than pensions (OPEB) are provided for retired employees under an AEP System plan. Substantially all employees are eligible for postretirement health care and life insurance if they retire from active service after reaching age 55 and have at least 10 service years. The funding policy for OPEB cost is to make contributions to an external Voluntary Employees Beneficiary Association trust fund equal to the incremental OPEB costs (i.e., the amount that the total postretirement benefits cost under SFAS 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions," exceeds the pay-as-you-go amount). Contributions were $6.3 million in 1997, $8.4 million in 1996 and $10.3 million in 1995. OPEB costs are determined by the application of AEP System actuarial assumptions to each company's employee complement. The Company's annual accrued costs for 1997, 1996 and 1995 required by SFAS 106 for employees and retirees were $11.5 million, $12.8 million and $13.6 million, respectively.

An employee savings plan is offered which allows participants to contribute up to 17% of their salaries into various investment alternatives, including AEP Co., Inc. common stock. An employer matching contribution, equaling one-half of the employees' contribution to the plan up to a maximum of 3% of the employees' base salary, is invested in AEP Co., Inc. common stock. The employer's annual contributions totaled $4 million in 1997, $3.7 million in 1996 and $3.9 million in 1995.

6. SUPPLEMENTARY INFORMATION:

	Year Ended December 31,		
	1997	1996	1995
		(in thousands)	
Cash was paid for:			
Interest (net of capitalized amounts)	$ 62,274	$ 64,117	$71,457
Income Taxes	120,212	125,707	88,675
Noncash Acquisitions Under Capital Leases	111,395	48,305	32,073

In connection with the 1996 early termination of a western coal land sublease the Company will receive cash payments from the lessee of $30.8 million over a ten-year period which has been recorded at a net present value of $22.8 million. In connection with the 1995 sale of western coal land and equipment the Company will receive cash payments from the buyer of $31.5 million over a six year period which has been recorded at a net present value of $26.9 million. In connection with construction of facilities in 1995 to provide service to a new customer the Company will receive cash payments of $21.4 million plus accrued interest over 20 years. The long-term portion of these receivables is recorded as other property and investments and the current portion is recorded as miscellaneous accounts receivable.

7. FEDERAL INCOME TAXES:

The details of federal income taxes as reported are as follows:

	Year Ended December 31,		
	1997	1996 (in thousands)	1995
Charged (Credited) to Operating Expenses (net):			
Current	$ 75,442	$110,133	$ 75,686
Deferred	3,088	(24,730)	(13,732)
Deferred Investment Tax Credits	(7,786)	(7,874)	(7,929)
Total	70,744	77,529	54,025
Charged (Credited) to Nonoperating Income (net):			
Current	3,287	182	12,872
Deferred	834	43	(9,832)
Deferred Investment Tax Credits	(642)	(855)	(1,075)
Total	3,479	(630)	1,965
Total Federal Income Taxes as Reported	$ 74,223	$ 76,899	$ 55,990

The following is a reconciliation 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 federal income taxes reported.

	Year Ended December 31,		
	1997	1996 (in thousands)	1995
Net Income	$146,740	$157,153	$141,092
Federal Income Taxes	74,223	76,899	55,990
Pre-tax Book Income	$220,963	$234,052	$197,082
Federal Income Tax on Pre-tax Book Income at Statutory Rate (35%)	$77,337	$81,918	$68,979
Increase (Decrease) in Federal Income Tax Resulting From the Following Items:			
Depreciation	14,082	13,880	8,954
Corporate Owned Life Insurance	(3,348)	(2,178)	(5,187)
Investment Tax Credits (net)	(8,428)	(8,729)	(9,004)
Other	(5,420)	(7,992)	(7,752)
Total Federal Income Taxes as Reported	$74,223	$76,899	$55,990
Effective Federal Income Tax Rate	33.6%	32.9%	28.4%

The following tables show the elements of the net deferred tax liability and the significant temporary differences giving rise to such deferrals:

	December 31,	
	1997	1996 (in thousands)
Deferred Tax Assets	$ 223,772	$ 241,842
Deferred Tax Liabilities	(783,480)	(836,721)
Net Deferred Tax Liabilities	$(559,708)	$(594,879)
Property Related Temporary Differences	$(471,898)	$(480,818)
Amounts Due From Customers For Future Federal Income Taxes	(74,282)	(79,658)
Deferred State Income Taxes	(65,679)	(89,471)
Deferred Net Gain - Rockport Plant Unit 2	32,347	33,644
All Other (net)	19,804	21,424
Total Net Deferred Tax Liabilities	$(559,708)	$(594,879)

The Company and its subsidiaries join in the filing of a consolidated federal income tax return with their affiliated companies in the AEP System. The allocation of the AEP System's current consolidated federal income tax to the AEP System companies is in accordance with SEC rules under the 1935 Act. These rules permit the allocation of the benefit of current tax losses to the System companies giving rise to them in determining their current tax expense. The tax loss of the parent company, AEP Co., Inc., is allocated to its subsidiaries with taxable income. With the exception of the loss of the System parent company, the method of allocation approximates a separate return result for each company in the consolidated group.

The AEP System has settled with the Internal Revenue Service (IRS) all issues from the audits of the consolidated federal income tax returns for the years prior to 1991. Returns for the years 1991 through 1996 are presently open and under audit by the IRS. During the audit the IRS agents requested a ruling from their National Office that certain interest deductions relating to corporate owned life insurance (COLI) claimed by the Company should not be allowed. The COLI program was established in 1990 as part of the Company's strategy to fund and reduce cost of medical benefits for retired employees. AEP filed a brief with the IRS National Office refuting the agents' position. Although no adjustments have been proposed, a disallowance of the COLI interest deductions through December 31, 1997 would reduce earnings by approximately $59 million (including interest). Management believes it has meritorious defenses and will vigorously contest any proposed adjustments. No provisions for this amount have been recorded. In the event the Company is unsuccessful it could have a material adverse impact on results of operations and cash flows.

8. FAIR VALUE OF FINANCIAL INSTRUMENTS:

Nuclear Trust Funds Recorded at Market Value

The Nuclear Decommissioning and Spent Nuclear Fuel Disposal Trust Fund investments are recorded at market value in accordance with SFAS 115 and consist of tax-exempt municipal bonds and other securities.

At December 31, 1997 and 1996 the fair values of trust fund investments were $566 million and $491 million, respectively. Accumulated gross unrealized holding gains were $41 million and $21.9 million and accumulated gross unrealized holding losses were $1.2 million at both December 31, 1997 and 1996. The change in market value in 1997, 1996 and 1995 was a net unrealized holding gain of $19.1 million, $2.6 million and $24.9 million, respectively.

The trust fund investments' cost basis by security type were:

	December 31,	
	1997	1996
	(in thousands)	
Tax-Exempt Bonds	$335,358	$340,290
Equity Securities	74,398	54,389
Treasury bonds	44,200	26,958
Corporate Bonds	9,167	7,977
Cash, Cash Equivalents and Interest Accrued	63,392	40,430
Total	$526,515	$470,044

Proceeds from sales and maturities of securities of $147.3 million during 1997 resulted in $3.9 million of realized gains and $1.4 million of realized losses. Proceeds from sales and maturities of securities of $115.3 million during 1996 resulted in $2.6 million of realized gains and $2.1 million of realized losses. Proceeds from sales and maturities of securities of $78.2 million during 1995 resulted in $1.4 million of realized gains and $0.3 million of realized losses. The cost of securities for determining realized gains and losses is original acquisition cost including amortized premiums and discounts.

At December 31, 1997, the year of maturity of trust fund investments, other than equity securities, was:

	(in thousands)
1998	$ 87,063
1999-2002	127,575
2003-2007	182,873
After 2007	54,606
Total	$452,117

Other Financial Instruments Recorded at Historical Cost

The carrying amounts 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. Fair values for preferred stocks subject to mandatory redemption were $73 million and $137 million at December 31, 1997 and 1996,

respectively, and for long-term debt were $1.1 billion at each year end. The carrying amounts for preferred stock subject to mandatory redemption were $68 million and $135 million and for long-term debt were $1.0 billion at December 31, 1997 and 1996, respectively. Fair values 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 carrying amount of the spent nuclear fuel disposal trust funds approximates the Company's estimate of the pre-April 1983 SNF liability.

9. LEASES:

Leases of property, plant and equipment are for periods of up to 35 years and require payments of related property taxes, maintenance and operating costs. The Company is leasing 50% of the 1300 MW Rockport 2 generating unit under an operating lease. The lease has 25 years remaining life and total minimum lease payments of $1.8 billion. 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,		
	1997	1996	1995
	(in thousands)		
Operating Leases	$ 92,067	$ 96,096	$ 96,472
Amortization of Capital Leases	42,882	55,789	45,843
Interest on Capital Leases	9,737	10,624	9,987
Total Rental Costs	$144,686	$162,509	$152,302

Properties under capital leases and related obligations recorded on the Consolidated Balance Sheets are as follows:

	December 31,	
	1997	1996
	(in thousands)	
Electric Utility Plant:		
Production	$ 9,218	$ 7,410
Distribution	14,660	14,699
General:		
Nuclear Fuel (net of amortization)	103,939	59,681
Other	61,268	60,949
Total Electric Utility Plant	189,085	142,739
Accumulated Amortization	31,358	28,598
Net Electric Utility Plant	157,727	114,141
Other Property	40,746	19,035
Accumulated Amortization	3,246	2,211
Net Other Property	37,500	16,824
Net Properties under Capital Leases	$195,227	$130,965
Capital Lease Obligations:*		
Noncurrent Liability	$161,194	$101,225
Liability Due Within One Year	34,033	29,740
Total Capital Lease Obligations	$195,227	$130,965

* Represents the present value of future minimum lease payments.

The noncurrent portion of capital lease obligations is included in other noncurrent liabilities in the Consolidated Balance Sheets.

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

Future minimum lease payments consisted of the following at December 31, 1997:

	Capital Leases	Non-Cancelable Operating Leases
	(in thousands)	
1998	$ 16,362	$ 96,974
1999	15,005	92,734
2000	13,593	92,472
2001	11,927	91,684
2002	22,520	90,655
Later Years	47,767	1,631,759
Total Future Minimum Lease Payments	127,174(a)	$2,096,278
Less Estimated Interest Element	35,886	
Estimated Present Value of Future Minimum Lease Payments	91,288	
Unamortized Nuclear Fuel	103,939	
Total	$195,227	

(a) Excludes nuclear fuel rentals which 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.

10. CUMULATIVE PREFERRED STOCK:

At December 31, 1997, authorized shares of cumulative preferred stock were as follows:

Par Value	Shares Authorized
$100	2,250,000
25	11,200,000

The cumulative preferred stock is callable at the price indicated below plus accrued dividends. The involuntary liquidation preference is par value. Unissued shares of the cumulative preferred stock may or may not possess mandatory redemption characteristics upon issuance. During 1996 the Company redeemed and canceled 300,000 shares of the 7.08% series not subject to mandatory redemption.

A. Cumulative Preferred Stock Not Subject to Mandatory Redemption:

Series	Call Price December 31, 1997	Par Value	Number of Shares Redeemed Year Ended December 31, 1997	1996	1995	Shares Outstanding December 31, 1997	Amount December 31, 1997 (in thousands)	1996
4-1/8%	$106.125	$100	59,760	233	-	60,007	$6,001	$11,977
4.56%	102	100	44,788	-	-	15,212	1,521	6,000
4.12%	102.728	100	20,869	-	-	19,131	1,913	4,000
							$9,435	$21,977

B. Cumulative Preferred Stock Subject to Mandatory Redemption:

Series(a)	Par Value	Number of Shares Redeemed Year Ended December 31, 1997	1996	1995	Shares Outstanding December 31, 1997	Amount December 31, 1997 (in thousands)	1996
5.90% (b)	$100	233,000	-	-	167,000	$16,700	$ 40,000
6-1/4%(b)	100	97,500	-	-	202,500	20,250	30,000
6.30% (b)	100	217,550	-	-	132,450	13,245	35,000
6-7/8%(c)	100	117,500	-	-	182,500	18,250	30,000
						$68,445	$135,000

(a) Not callable until after 2002. There are no aggregate sinking fund provisions through 2002.

(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 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 1997 may be applied to meet the sinking fund requirement.

11. LONG-TERM DEBT AND LINES OF CREDIT:

Long-term debt by major category was outstanding as follows:

	December 31, 1997	December 31, 1996
	(in thousands)	
First Mortgage Bonds	$ 520,317	$ 522,507
Installment Purchase Contracts	309,269	309,120
Other Long-term Debt (a)	180,837	171,706
Junior Debentures	38,814	38,771
	1,049,237	1,042,104
Less Portion Due Within One Year	35,000	-
Total	$1,014,237	$1,042,104

(a) Represents a Nuclear Fuel Disposal liability including interest accrued payable to the Department of Energy. See Note 3.

First mortgage bonds outstanding were as follows:

% Rate	Due	December 31, 1997	December 31, 1996
		(in thousands)	
7.00	1998 - May 1	$ 35,000	$ 35,000
7.30	1999 - December 15	35,000	35,000
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
6.80	2003 - July 1	20,000	20,000
6.55	2003 - October 1	20,000	20,000
6.10	2003 - November 1	30,000	30,000
6.55	2004 - March 1	25,000	25,000
8.75	2022 - May 1	-	50,000
8.50	2022 - December 15	75,000	75,000
7.80	2023 - July 1	20,000	20,000
7.35	2023 - October 1	20,000	20,000
7.20	2024 - February 1	40,000	40,000
7.50	2024 - March 1	25,000	25,000
Unamortized Discount (net)		(2,683)	(2,493)
		520,317	522,507
Less Portion Due Within One Year		35,000	-
Total		$485,317	$522,507

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, 1997	December 31, 1996
		(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		(2,731)	(2,880)
Total		$309,269	$309,120

(a) A variable interest rate is determined weekly. The average weighted interest rate was 4.3% for 1997 and 3.5% for 1996.
(b) An adjustable interest rate can be a daily, weekly, commercial paper or term rate as designated by the Company. A weekly rate was selected which ranged from 3.0% to 4.6% in 1997 and from 2.4% to 5.0% in 1996 and averaged 3.8% and 3.4% during 1997 and 1996, respectively.

Under the terms of certain installment purchase contracts, the Company is required to pay amounts sufficient to enable the cities to pay interest on and the principal (at stated maturities and upon mandatory redemption) 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 2000. 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.

Junior debentures are composed of the following:

% Rate	Due	December 31, 1997 (in thousands)	December 31, 1996 (in thousands)
8.00	2026 - March 31	$40,000	$40,000
Unamortized Discount		(1,186)	(1,229)
Total		$38,814	$38,771

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 the Company.

At December 31, 1997, future annual long-term debt payments are as follows:

	Amount (in thousands)
1998	$ 35,000
1999	35,000
2000	98,000
2001	40,000
2002	140,000
Later Years	707,837
Total Principal Amount	1,055,837
Unamortized Discount	(6,600)
Total	$1,049,237

Short-term debt borrowings are limited by provisions of the 1935 Act to $175 million. Lines of credit are shared with AEP System companies and at December 31, 1997 and 1996 were available in the amounts of $442 million and $409 million, respectively. Facility fees of approximately 1/10 of 1% of the short-term lines of credit are required by the banks to maintain the lines of credit.

Outstanding short-term debt consisted of:

	Balance Outstanding (in thousands)	Year-end Weighted Average Interest Rate
December 31, 1997:		
Notes Payable	$ 56,410	6.3%
Commercial Paper	63,190	6.8
Total	$119,600	6.6
December 31, 1996:		
Notes Payable	$ 3,900	5.5%
Commercial Paper	39,600	7.2
Total	$43,500	7.0

12. COMMON SHAREHOLDER'S EQUITY:

Mortgage indentures, charter provisions and orders of regulatory authorities place various restrictions on the use of retained earnings for the payment of cash dividends on common stock. At December 31, 1997, $5.9 million of retained earnings were restricted. Regulatory approval is required to pay dividends out of paid-in capital.

In 1997, 1996 and 1995 net changes to paid-in capital of $1,200,000, $170,000 and $(2,548,000) respectively, represented gains and expenses associated with cumulative preferred stock transactions.

13. UNAUDITED QUARTERLY FINANCIAL INFORMATION:

Quarterly Periods Ended	Operating Revenues (in thousands)	Operating Income (in thousands)	Net Income (in thousands)
1997			
March 31	$341,313	$59,894	$44,259
June 30	320,508	50,140	33,908
September 30	362,058	60,449	45,091
December 31	368,038	37,305	23,482
1996			
March 31	329,883	53,018	35,767
June 30	323,494	50,430	33,507
September 30	339,847	61,123	44,546
December 31	335,269	55,846	43,333

INDEPENDENT AUDITORS' REPORT

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

We have audited the accompanying consolidated balance sheets of Indiana Michigan Power Company and its subsidiaries as of December 31, 1997 and 1996, and the related consolidated statements of income, retained earnings, and cash flows for each of the three years in the period ended December 31, 1997. 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 generally accepted auditing standards. 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, 1997 and 1996, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1997 in conformity with generally accepted accounting principles.

Deloitte + Touche LLP

DELOITTE & TOUCHE LLP
Columbus, Ohio
February 24, 1998

OPERATING STATISTICS

	1997	1996	1995	1994	1993
OPERATING REVENUES (in thousands):					
Retail:					
Residential:					
Without Electric Heating	$ 237,475	$ 232,212	$ 239,266	$ 227,358	$ 205,315
With Electric Heating	110,547	111,558	109,504	107,523	97,568
Total Residential	348,022	343,768	348,770	334,881	302,883
Commercial	264,031	253,750	256,319	247,938	220,938
Industrial	332,218	312,777	298,256	291,527	250,939
Miscellaneous	6,465	6,445	6,482	6,316	5,593
Total Retail	950,736	916,740	909,827	880,662	780,353
Wholesale (sales for resale)	415,077	391,478	357,441	352,889	404,910
Total Revenues from Energy Sales	1,365,813	1,308,218	1,267,268	1,233,551	1,185,263
Provision for Refunds of Revenues Collected in Prior Years	-	-	-	-	(755)
Total Net of Provision for Refunds	1,365,813	1,308,218	1,267,268	1,233,551	1,184,508
Other	26,104	20,275	15,889	17,758	18,135
Total Operating Revenues	$1,391,917	$1,328,493	$1,283,157	$1,251,309	$1,202,643
SOURCES AND USES OF ENERGY (in millions of kilowatthours):					
Sources:					
Net Generated:					
Fossil Fuel	14,193	13,304	12,850	13,022	12,236
Nuclear Fuel	10,421	16,396	13,999	9,291	16,313
Hydroelectric	133	99	86	95	106
Total Net Generated	24,747	29,799	26,935	22,408	28,655
Purchased and Power Pool	11,649	7,581	5,871	5,757	4,879
Total Sources	36,396	37,380	32,806	28,165	33,534
Less: Losses, Company Use, Etc.	1,850	1,795	1,700	1,398	1,349
Net Sources	34,546	35,585	31,106	26,767	32,185
Uses:					
Retail Sales:					
Residential:					
Without Electric Heating	3,307	3,329	3,390	3,210	3,178
With Electric Heating	1,768	1,811	1,768	1,727	1,706
Total Residential	5,075	5,140	5,158	4,937	4,884
Commercial	4,349	4,328	4,300	4,148	3,977
Industrial	7,541	7,295	6,582	6,453	6,025
Miscellaneous	82	82	82	82	83
Total Retail	17,047	16,845	16,122	15,620	14,969
Wholesale Sales (sales for resale)	17,499	18,740	14,984	11,147	17,216
Total Uses	34,546	35,585	31,106	26,767	32,185

OPERATING STATISTICS (Concluded)

	1997	1996	1995	1994	1993
AVERAGE COST OF FUEL CONSUMED (in cents):					
Per Million Btu:					
Coal	124	122	126	124	130
Nuclear	49	44	43	42	36
Overall	89	74	78	85	72
Per Kilowatthour Generated:					
Coal	1.23	1.22	1.23	1.21	1.27
Nuclear	.53	.47	.47	.47	.40
Overall	.93	.80	.83	.90	.77

	1997	1996	1995	1994	1993
RESIDENTIAL SERVICE - AVERAGES:					
Annual Kwh Use per Customer:					
With Electric Heating	17,583	18,206	18,044	17,907	17,980
Total	10,560	10,791	10,943	10,572	10,559
Annual Electric Bill:					
With Electric Heating	$1,099.34	$1,121.41	$1,117.55	$1,115.19	$1,028.26
Total	$724.16	$721.76	$739.99	$717.17	$654.76
Price per Kwh (in cents):					
With Electric Heating	6.25	6.16	6.19	6.23	5.72
Total	6.86	6.69	6.76	6.78	6.20

	1997	1996	1995	1994	1993
NUMBER OF CUSTOMERS:					
Year-End:					
Retail:					
Residential:					
Without Electric Heating	383,314	378,757	375,929	372,473	369,385
With Electric Heating	101,492	100,372	99,105	97,402	95,795
Total Residential	484,806	479,129	475,034	469,875	465,180
Commercial	57,311	55,869	55,077	53,927	53,081
Industrial	5,484	5,345	5,316	5,213	5,157
Miscellaneous	1,855	1,820	1,797	1,806	1,783
Total Retail	549,456	542,163	537,224	530,821	525,201
Wholesale (sales for resale)	122	85	62	54	56
Total Electric Customers	549,578	542,248	537,286	530,875	525,257

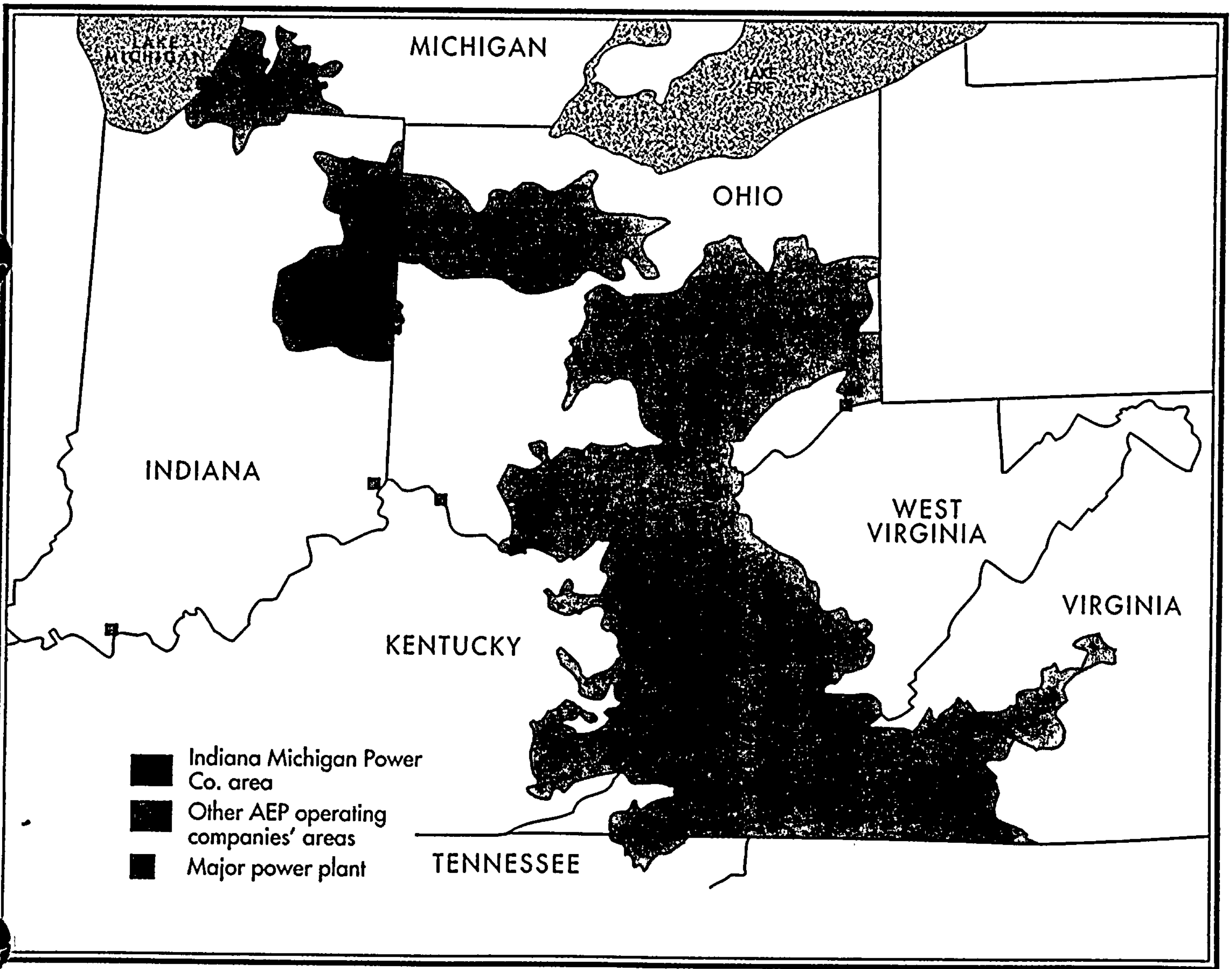
INDIANA MICHIGAN POWER COMPANY
AND SUBSIDIARIES

DIVIDENDS AND PRICE RANGES OF CUMULATIVE PREFERRED STOCK By Quarters (1997 and 1996)

	1997 - Quarters				1996 - Quarters			
	1st	2nd	3rd	4th	1st	2nd	3rd	4th
CUMULATIVE PREFERRED STOCK								
($100 Par Value)								
4-1/8% Series								
Dividends Paid Per Share	$1.03125	$1.03125	$1.03125	$1.03125	$1.03125	$1.03125	$1.03125	$1.03125
Market Price - $ Per Share								
(CSE) - High	-	-	-	-	-	-	-	-
- Low	-	-	-	-	-	-	-	-
4.56% Series								
Dividends Paid Per Share	$1.14	$1.14	$1.14	$1.14	$1.14	$1.14	$1.14	$1.14
Market Price - $ Per Share								
(OTC)								
Ask - High	-	-	-	-	-	-	-	-
- Low	-	-	-	-	-	-	-	-
Bid - High	52	52	57-5/8	58-1/4	51	51-1/4	52	52
- Low	52	52	52	57-5/8	49-3/8	51	51-1/4	52
4.12% Series								
Dividends Paid Per Share	$1.03	$1.03	$1.03	$1.03	$1.03	$1.03	$1.03	$1.03
Market Price - $ Per Share								
(OTC)								
Ask - High	-	-	-	-	-	-	-	-
- Low	-	-	-	-	-	-	-	-
Bid - High	63-1/8	58	58-1/4	58-1/4	51	49	49-3/4	50
- Low	50	58	58	58-1/4	48-1/4	48-3/4	49	49-3/4
5.90% Series								
Dividends Paid Per Share	$1.475	$1.475	$1.475	$1.475	$1.475	$1.475	$1.475	$1.475
Market Price - $ Per Share								
(OTC)								
Ask (high/low)	-	-	-	-	-	-	-	-
Bid (high/low)	-	-	-	-	-	-	-	-
6-1/4% Series								
Dividends Paid Per Share	$1.5625	$1.5625	$1.5625	$1.5625	$1.5625	$1.5625	$1.5625	$1.5625
Market Price - $ Per Share								
(OTC)								
Ask (high/low)	-	-	-	-	-	-	-	-
Bid (high/low)	-	-	-	-	-	-	-	-
6.30% Series								
Dividends Paid Per Share	$1.575	$1.575	$1.575	$1.575	$1.575	$1.575	$1.575	$1.575
Market Price - $ Per Share								
(OTC)								
Ask (high/low)	-	-	-	-	-	-	-	-
Bid (high/low)	-	-	-	-	-	-	-	-
6-7/8% Series								
Dividends Paid Per Share	$1.71875	$1.71875	$1.71875	$1.71875	$1.71875	$1.71875	$1.71875	$1.71875
Market Price - $ Per Share								
(OTC)								
Ask (high/low)	-	-	-	-	-	-	-	-
Bid (high/low)	-	-	-	-	-	-	-	-
7.08% Series (a)								
Dividends Paid Per Share					$1.77			
Market Price - $ Per Share								
(NYSE) - High					-			
- Low					-			

CSE - Chicago Stock Exchange
OTC - Over-the-Counter
NYSE - New York Stock Exchange
Note - The above bid and asked quotations represent prices between dealers and do not represent actual transactions.
Market quotations provided by National Quotation Bureau, Inc.
Dash indicated quotation not available.
(a) Redeemed April 1996

Indiana Michigan Power Service Area and the American Electric Power System



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ATTACHMENT 2 TO AEP:NRC:0909N

INDIANA MICHIGAN POWER COMPANY'S
PROJECTED CASH FLOW FOR 1998

Indiana Michigan Power Co.
1998 Forecasted Sources and Uses of Funds
$Millions

	Projected 1998
Net Income After Taxes	148.6
Less: Dividends	117.5
	31.1
Adjustments:	
Depreciation and Amortization	145.3
Deferred Operating Costs	4.9
Deferred Federal Income Taxes and Investment Tax Credits	(24.7)
AFUDC	(6.3)
Other	30.2
Total Adjustments	149.4
Internal Cash Flow	**180.5**
Average Quarterly Cash Flow	45.1
Average Cash Balances and Short-Term Investments	3.7
Total	48.8