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SUBJECT: Forwards Indiana Michigan Power Co annual rept for 1994 & projected cash flow for 1995,per 10CFR50.71(b) & 10CFR140.21(e).

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Power Company
P.O. Box 16631
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AEP
INDIANA
MICHIGAN
POWER

March 31, 1995 AEP:NRC:0909K

Docket Nos.: 50-315
50-316

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D. C. 20555

Gentlemen:

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

Attachment 1 contains the Indiana Michigan Power Company's (I&M) annual report for 1994. Attachment 2 contains a copy of I&M's projected cash flow for 1995. These reports are submitted pursuant to 10 CFR 50.71(b) and 10 CFR 140.21(e).

Sincerely,

SJ Brewer for
E. E. Fitzpatrick
Vice President

eh

Attachments

cc: A. A. Blind
G. Charnoff
J. B. Martin
NFEM Section Chief
NRC Resident Inspector - Bridgman
J. R. Padgett

070047

M004 /1

ATTACHMENT 1 TO AEP:NRC:0909K

INDIANA MICHIGAN POWER COMPANY'S

ANNUAL REPORT FOR 1994

Indiana Michigan Power Company

1994 Annual Report

AEP AMERICAN ELECTRIC POWER

CONTENTS

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

BACKGROUND

INDIANA MICHIGAN POWER COMPANY (the Company) is engaged in the generation, purchase, transmission and distribution of electric power. The Company serves approximately 531,000 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 and electric cooperatives. Approximately 82% of the Company's retail sales are in Indiana and 18% in Michigan. The principal industries served are primary metals, transportation equipment, fabricated metal products, electrical and electronic machinery, rubber and miscellaneous plastic products and chemicals and allied products.

The Company is a subsidiary of American Electric Power Company, Inc., and was organized under the laws of Indiana on February 21, 1925. 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 4,434 megawatts (mw) of generating capacity which includes 2,295 mw of coal-fired generation and the 2,110 mw Donald C. Cook Nuclear Plant. 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 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 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 Power Company, 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). In addition, the Company is interconnected through the AEP System with two other affiliated companies, Kingsport Power Company and Wheeling Power Company and with numerous unaffiliated utilities.

DIRECTORS

Mark A. Bailey
Peter J. DeMaria
William N. D'Onofrio
A. Joseph Dowd (a)
E. Linn Draper, Jr.
William J. Lhota
Gerald P. Maloney
James J. Markowsky (b)
Richard C. Menge
Albert H. Potter (c)
Ronald E. Prater (d)
David B. Synowiec (d)
Dale M. Trenary (c)
William E. Walters

OFFICERS

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

Richard C. Menge
President and Chief Operating Officer

Mark A. Bailey
Vice President

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

Peter J. DeMaria
Vice President and Treasurer

William N. D'Onofrio
Vice President

A. Joseph Dowd (a)
Vice President

Eugene E. Fitzpatrick
Vice President

William J. Lhota
Vice President

Gerald P. Maloney
Vice President

James J. Markowsky
Vice President

John F. DiLorenzo, Jr.
Secretary

Elio Bafile
Assistant Secretary and
Assistant Treasurer

Jeffrey D. Cross
Assistant Secretary

Carl J. Moos
Assistant Secretary

John B. Shinnock
Assistant Secretary

Leonard V. Assante
Assistant Treasurer

Bruce M. Barber
Assistant Treasurer

Gerald R. Knorr
Assistant Treasurer

As of January 1, 1995 the current directors and officers of Indiana Michigan Power Company were employees of American Electric Power Service Corporation with nine exceptions: Messrs. Bafile, Bailey, Blind, D'Onofrio, Menge, Moos, Potter, Trenary and Walters, who were employees of Indiana Michigan Power Company.

(a) Resigned November 30, 1994
(b) Elected January 24, 1995
(c) Elected April 26, 1994
(d) Resigned April 26, 1994
(e) Elected May 1, 1994

Selected Consolidated Financial Data

	Year Ended December 31,				
	1994	1993	1992	1991	1990
			(in thousands)		
INCOME STATEMENTS DATA:					
Operating Revenues	$1,251,309	$1,202,643	$1,196,755	$1,225,867	$1,271,514
Operating Expenses	1,029,578	992,723	1,001,235	998,578	1,070,023
Operating Income	221,731	209,920	195,520	227,289	201,491
Nonoperating Income (Loss)	7,428	(234)	14,115	(3,721)	7,557
Income Before Interest Charges	229,159	209,686	209,635	223,568	209,048
Interest Charges	71,688	80,373	85,687	86,636	90,657
Net Income	157,471	129,313	123,948	136,932	118,391
Preferred Stock Dividend Requirements	11,650	14,225	15,417	15,417	15,587
Earnings Applicable to Common Stock	$ 145,821	$ 115,088	$ 108,531	$ 121,515	$ 102,804

	December 31,				
	1994	1993	1992	1991	1990
BALANCE SHEETS DATA:			(in thousands)		
Electric Utility Plant	$4,269,306	$4,290,957	$4,266,480	$4,135,820	$4,066,227
Accumulated Depreciation and Amortization	1,659,940	1,714,829	1,631,438	1,521,349	1,421,285
Net Electric Utility Plant	$2,609,366	$2,576,128	$2,635,042	$2,614,471	$2,644,942
Regulatory Assets	$ 481,212	$ 441,681	$ 208,938	$ 141,517	$ 164,739
Total Assets	$3,915,729	$3,765,458	$3,645,798	$3,481,878	$3,501,925
Common Stock and Paid-in Capital	$ 791,095	$ 791,517	$ 782,741	$ 782,741	$ 782,741
Retained Earnings	216,658	177,638	171,309	169,243	150,408
Total Common Shareowner's Equity	$1,007,753	$ 969,155	$ 954,050	$ 951,984	$ 933,149
Cumulative Preferred Stock:					
Not Subject to Mandatory Redemption	$ 52,000	$ 87,000	$ 197,000	$ 197,000	$ 197,000
Subject to Mandatory Redemption (a)	135,000	100,000	-	-	-
Total Cumulative Preferred Stock	$ 187,000	$ 187,000	$ 197,000	$ 197,000	$ 197,000
Long-term Debt (a)	$1,069,887	$1,073,154	$1,211,623	$1,130,709	$1,133,833
Obligations Under Capital Leases (a)	$ 152,589	$ 98,753	$ 126,689	$ 102,985	$ 133,447
Total Capitalization and Liabilities	$3,915,729	$3,765,458	$3,645,798	$3,481,878	$3,501,925

(a) Including portion due within one year.

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

Results of Operations

Net Income Increases

Net income increased 21.8% to $157 million in 1994 mainly due to a retail base rate increase in the Company's Indiana jurisdiction, reduced interest expense due to the retirement of long-term debt, the adoption of Statement of Financial Accounting Standards No. 109, *Accounting for Income Taxes* (SFAS 109) in 1993 and the retirement of a generating plant. The increase in net income in 1993 of 4.3% was the result of lower interest expense due to the retirement of long-term debt and the return to service of the Company's nuclear units from refueling and maintenance outages completed in 1992.

Operating Revenues Increase and Energy Sales Decline

Operating revenues increased 4% in 1994 and a minor amount in 1993. The changes in revenues can be analyzed as follows:

	Increase (Decrease) From Previous Year			
(dollars in millions)	1994		1993	
	Amount	%	Amount	%
Retail:				
Price variance	$ 69.8		$ (75.1)	
Volume variance	30.5		40.3	
	100.3	12.9	(34.8)	(4.3)
Wholesale:				
Price variance	90.7		(137.2)	
Volume variance	(142.7)		172.7	
	(52.0)	(12.8)	35.5	9.6
Other Operating Revenues	0.4		5.2	
Total	$ 48.7	4.0	$ 5.9	0.5

Retail operating revenues increased 13% during 1994 reflecting a $34.7 million annual rate increase in the Indiana jurisdiction, increased decommissioning expense recoveries in the Michigan jurisdiction, the operation of the retail fuel and power supply cost recovery mechanisms and a 4% increase in energy sales. The increase in retail energy sales in 1994 resulted from the growth in the number of customers served in all retail customer classes and increased usage by industrial and commercial customers. Energy sales to residential customers remained constant in 1994 as mild weather during most of the year offset the effect of the severe weather in January and the unseasonably warm weather in May and June.

Although wholesale energy sales declined 35% in 1994, wholesale revenues declined only 13% reflecting the continuing effect of fixed capacity charges recovered from the AEP System Power Pool (Power Pool), which are unrelated to the amount of energy actually delivered, and an increase in take-or-pay capacity reservation charges collected from unaffiliated utilities. The decline in wholesale energy sales reflects the decrease in energy available for delivery to the Power Pool due to the scheduled refueling and maintenance outages at both of the Company's nuclear units in 1994 and lower energy sales by the Power Pool due to mild weather throughout most of 1994. While severe weather in January 1994 and hot June weather increased the Power Pool's short-term wholesale sales in those months, the mild weather throughout the remainder of 1994, combined with increased competition in the wholesale market, reduced short-term sales for the year.

Although retail energy sales increased 5% in 1993, retail revenues decreased 4% reflecting the operation of fuel and power supply recovery mechanisms due to the increased availability in 1993 of the lower cost nuclear units. Under the retail jurisdictional fuel clauses, revenues were accrued in 1992 for future recovery of higher cost replacement power during the nuclear outages. In 1993, with the nuclear units returned to full service, the accruals for higher cost coal based replacement power ceased. The increase in retail energy sales in 1993 reflects continued growth in industrial customer usage, a return to normal weather and growth in the number of customers in all retail classes.

Wholesale revenues increased 10% and wholesale energy sales increased 47% in 1993 due primarily to the increased availability of the nuclear generating capacity making more energy available for sale to the Power Pool and increased sales by the Power Pool to unaffiliated utilities which the Company shares as a member of the Pool.

Operating Expenses Increase

Changes in the components of operating expenses were as follows:

(dollars in millions)	Increase (Decrease) From Previous Year 1994 Amount	1994 %	1993 Amount	1993 %
Fuel	$(18.5)	(8.4)	$ 26.4	13.6
Purchased Power	23.0	21.2	(72.0)	(40.0)
Other Operation	28.5	10.8	12.6	5.0
Maintenance	(3.2)	(2.3)	4.9	3.5
Depreciation and Amortization	(2.6)	(1.8)	5.4	4.1
Amortization of Rockport Plant Unit 1 Phase-in Plan Deferrals	-	-	(0.7)	(4.0)
Taxes Other Than Federal Income Taxes	3.3	4.8	5.7	9.2
Federal Income Taxes	6.4	18.4	9.2	36.1
Total	$ 36.9	3.7	$ (8.5)	(0.9)

Fuel expense declined in 1994 due to a significant reduction in nuclear generation, partially offset by a 6% increase in fossil generation. Nuclear generation declined by 43% due to the scheduled refueling outages at both nuclear units. The increase in 1993 fuel expense was mainly attributable to a significant increase in nuclear generation and increased fossil generation, partially offset by a decrease in the average cost of fuel. Refueling and maintenance outages in 1992 coupled with the absence of outages in 1993 accounted for the increase in nuclear generation.

The increase in purchased power expense in 1994 reflects increased energy receipts from the Power Pool to replace the nuclear power that was not available due to the scheduled nuclear refueling and maintenance outages in 1994 and increased purchases from unaffiliated utilities for immediate resale to other unaffiliated utilities. Purchased power expense declined in 1993 due to reduced energy receipts from the Power Pool because of the increased availability of both nuclear units and decreased purchases from AEP Generating Company (AEGCo), an affiliate that is not a member of the Power Pool. In 1993 energy purchased from AEGCo was reduced since both of AEGCo's generating units had outages for planned boiler maintenance and repairs.

Other operation expense increased in 1994 due to regulator approved increases in accruals of additional nuclear decommissioning expense and other postretirement benefits commensurate with rate recovery and the accrual of employee severance benefits resulting from the closing of the Breed Plant and the recommendations from an organizational review study. The 1993 increase also reflected increased nuclear costs including decommissioning accruals and other postretirement benefit accruals.

The increase in taxes other than federal income taxes in 1993 was primarily due to a substantial increase in Indiana supplemental net income tax. In 1992 Indiana supplemental net income tax was significantly reduced by the deduction of nuclear refueling and maintenance outage costs. There were no refueling outages in 1993.

Federal income taxes attributable to operations increased in both periods due to increased pre-tax operating income.

Nonoperating Income Increases and Financing Costs Decline

Nonoperating income increased in 1994 reflecting the favorable tax effect of the Breed Plant closing and the effect of the recordation in 1993 of the unfavorable effect of adopting SFAS 109 for nonutility assets and liabilities. The decline in nonoperating income in 1993 was due to the adoption of the new tax accounting standard, the effect of interest income recorded in 1992 from the settlement of prior years' federal income tax audits and the reversal in 1992 of a previously recorded provision for a loss as a result of the successful settlement of a coal royalty dispute in the state of Utah.

Interest charges declined in both 1994 and 1993 due to debt repayments and a refinancing program which lowered interest rates. In 1994 $10 million of long-term bonds were retired and $90 million were refinanced. During 1993 $142 million of long-term bonds were retired and $150 million of bonds and $97 million of installment purchase contracts were refinanced at lower rates.

Construction Spending

Gross plant and property additions were $212 million in 1994 and $125 million in 1993. Management estimates construction expenditures for the next three years to be $393 million including expenditures necessary to meet the requirements of the Clean Air Act Amendments of 1990. The funds for construction of new facilities and im-

provement of existing facilities can come from a combination of internally generated funds, short-term and long-term borrowings and investments in common equity by the Company's parent, American Electric Power Co., Inc. (AEP Co., Inc.). However, all of the construction expenditures for the next three years are expected to be financed internally. These estimated construction expenditures do not include any major new generating capacity.

Capital Resources

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, 1994, unused short-term lines of credit shared with other AEP System companies of $558 million were available. A charter provision limits the Company's short-term borrowings to $130 million. Periodic reductions of outstanding short-term debt are made through issuances of long-term debt and preferred stock and through additional capital contributions by the parent company.

The Company recently received regulatory approval to issue up to $160 million of long-term debt. Management expects to use the proceeds to retire short-term debt, to refinance higher cost and maturing long-term debt and to reacquire cumulative preferred stock.

The Company presently exceeds all minimum coverage requirements for issuance of preferred stock and long-term debt. At December 31, 1994, long-term debt and preferred stock coverage ratios were 5.08 and 2.74, respectively.

Competition

In exchange for the exclusive right to provide electric generation, transmission and distribution services within a designated service territory at cost-based regulated prices that provide the opportunity to earn a regulator-determined reasonable rate of return on shareholders' equity, electric utilities are obligated to serve all customers within such service territories. While the Company is a regulated monopoly, we have competed historically with self-generation and with distributors of alternative sources of energy, such as natural gas, fuel oil and coal, within our service area. In recent years regulated electric utilities have also competed with independent power producers for the right to build and operate new generating plant. The primary competitive factors have been price, reliability of service and the ability of customers to utilize sources of energy other than electric power. The lack of independent power producers and significant self generation in our service territory evidences our past ability to compete. With respect to alternative energy sources, management believes that the convenience and versatility of electricity and reliability of our service coupled with the limited ability of customers to substitute other energy sources for electric power have placed us in a favorable competitive position. However, we continue to work to improve the competitiveness, effectiveness and reliability of our product. The Company, for example, markets high-efficiency heat pumps and off-peak storage water heaters which make electricity competitive with natural gas for space and water heating.

Competition in the wholesale market, that is the sale of bulk power to other public and municipal utilities, is not new and has been increasing for a number of years. This is particularly true in the short-term market. The National Energy Policy Act of 1992 (the Energy Act) facilitated competition in the short and long-term wholesale market since, among other things, it authorized the Federal Energy Regulatory Commission (FERC) to order transmission access for wholesale transactions. The principal factors in competing for wholesale sales are price including fuel costs, availability of capacity, transmission capability and cost, and reliability of service. Management believes that over the years the Company has generally maintained a favorable competitive position in these factors. However, due to the recent availability of additional capacity of other utilities and reduced fuel prices, price competition, particularly in the short-term wholesale market, has been, and is expected to be important in the future.

With the passage of the Energy Act, the potential for retail wheeling, i.e., competition for retail sales, is getting considerable attention. While the Energy Act gave the FERC broad authority to mandate transmission access in the wholesale market, it prohibits the FERC from ordering retail wheeling. A number of state legislatures and state regulatory agencies have begun to study retail wheeling with encouragement from major industrial customers.

If it occurs, increased competition may require the resolution of some complex issues, such as

stranded investment and the obligation to serve. When a customer leaves a utility system there is an issue of who pays for regulatory assets, plant investment and commitments that are no longer needed. If a customer leaves its native electric supplier and later decides to return, the issue of whether the original local utility has an obligation to serve the returning customer must also be addressed. If not recovered directly from customers that choose another supplier and/or from the remaining regulated customers, the Company, like all electric utilities, will be required to address stranded investment losses that could result from any future loss of customers or reduced pricing from head-to-head competition. Management intends to seek recovery of any stranded investment, including regulatory assets, as an appropriate recovery of previously approved cost of service.

Activity-based budgeting and cost management techniques are being currently developed to enable management to cost logical work activities and services. By examining our operations by logical work units, the cost of all major activities can be better controlled, identified and evaluated to properly price our products and to eliminate unnecessary activities and their cost. Management believes these activities will enhance our ability to compete.

The development of tools and training to enable management to better manage the costs of operations are only one of the options currently being pursued. In 1994 the Company's management team has been:

- Reviewing and streamlining operations and staffing,
- Reducing layers of supervision,
- Expanding customer relations and service activities,
- Expanding its ability to help customers adopt new electro-technologies to reduce their usage of electricity, and
- Expanding strategic planning and management training activities.

Management is committed to maintaining and enhancing our business. Management is moving in "new directions" to maintain and improve our competitive position. Whether competition expands or not, these efforts should serve to lower cost of service and rates and improve sales through economic development in our service territory.

Environmental Concerns

Clean Air Act

The Clean Air Act Amendments of 1990 (CAAA) require, among other things, substantial reductions in sulfur dioxide and nitrogen oxide emissions from electric generating plants. The first phase of reductions in sulfur dioxide emissions (Phase I) began on January 1, 1995 and the second, more restrictive phase (Phase II) begins on January 1, 2000. The law also establishes a permanent nationwide cap on sulfur dioxide emissions after 1999.

Two of the Company's generating units, Tanners Creek Unit 4 and the Breed Plant, were affected by the first phase of the CAAA. Tanners Creek Unit 4 complied by fuel switching with minimal capital cost. Management decided to close the 325 megawatt Breed Plant in 1994, due to its design, age and the cost of complying with the CAAA. The closing of the Breed Plant did not adversely affect results of operations.

Phase II of the CAAA will require further compliance actions and additional costs. Management intends to seek timely recovery of all CAAA costs.

Global Climate Change

Concern about global climate change, or "the greenhouse effect" has been the focus of intensive debate within the United States and around the world. Much of the uncertainty about what effects greenhouse gas concentrations will have on the global climate results from a myriad of factors that affect climate. Based on the terms of a 1992 United Nations treaty that pledged the United States to reduce greenhouse gas emissions, the Clinton Administration developed a voluntary plan to reduce greenhouse gas emissions to 1990 levels by the year 2000. As part of this plan, the AEP System is participating with the U.S. Department of Energy (DOE) and other electric utility companies in a climate change program to limit future greenhouse gas emissions.

The climate change program applies a policy of proactive environmental stewardship, whereby actions are taken that make economic and environmental sense on their own merits, irrespective of the uncertain threat of global climate change. The plan includes energy conservation programs, improvements in fossil generation efficiency, increased use of nuclear capacity and forest man-

agement activities. However, should it be determined necessary to enact significant new measures to control the burning of coal, the cost of such measures if not recovered from ratepayers, could adversely impact results of operations and possibly financial condition.

EMF

The potential for electric and magnetic fields (EMF) from transmission and distribution facilities to adversely affect the public health is being extensively researched. The AEP System continues to support research to help determine the extent, if any, to which EMF may adversely impact public health. Our concern is that new laws imposing EMF limits may be passed or new regulations promulgated without sufficient scientific study and evidence to support them. As long as there is uncertainty about EMF, the Company and other electric utilities will have difficulty finding acceptable sites for their facilities, which could hamper economic growth within our service area. If the present energy delivery system must be changed because of EMF concerns, or if the courts conclude that EMF exposure harms individuals and that utilities are liable for damages, then the Company's results of operations and financial condition could be adversely affected, unless the costs can be recovered from ratepayers.

Hazardous Material

By-products from the generation of electricity include materials such as ash, slag, sludge, low-level radioactive waste and spent nuclear fuel. In addition, generating plants and transmission and distribution facilities have used asbestos, polychlorinated biphenyls (PCBs) and other hazardous and non-hazardous materials. The Company is currently incurring costs to safely store and dispose of such substances, and additional costs could be incurred to comply with new laws and regulations if enacted.

The Comprehensive Environmental Response Compensation and Liability Act (Superfund) addresses clean-up of hazardous substance disposal sites and authorizes the United States Environmental Protection Agency (Federal EPA) to administer the clean-up programs. The Company has been named by the Federal EPA as a "potentially responsible party" (PRP) for eight sites and has received information requests for three other sites. For four of the PRP sites, liability has been settled with no significant effect on results of operations. I&M also has been named as a PRP at one Illinois site and has received an information request for one Indiana site under similar state clean-up laws.

In all instances where the Company has been named a PRP or defendant, the disposal or recycling activity was in accordance with applicable laws and regulations. However, Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories. As a result, AEP has instituted a number of Systemwide policies that have raised the standard of care by going beyond regulatory requirements where appropriate.

While the potential liability for each site must be evaluated separately, several general statements can be made regarding such potential liability. The disposal by the Company at a particular site is often unsubstantiated; the quantity of material disposed of at a site was generally small; and the nature of the material generally disposed of was non-hazardous. Typically, the Company is one of many parties named PRPs for a site and, although liability is joint and several, at least some of the other parties are financially sound enterprises. Therefore, present estimates do not anticipate material clean-up costs for identified disposal sites. However, if for unknown reasons, significant costs are incurred for cleanup, results of operations and possibly financial condition would be adversely affected unless the costs can by recovered from insurance proceeds and/or with regulatory approval from ratepayers.

Nuclear Cost

The cost to operate and maintain the two-unit Donald C. Cook Nuclear Plant is impacted by Nuclear Regulatory Commission (NRC) requirements and the normal aging of the plant (Unit 1 began commercial operation in 1975 and Unit 2 in 1978). In addition, the cost to decommission the plant is affected by NRC regulations and the DOE's Spent Nuclear Fuel (SNF) disposal program. Studies completed in 1994 estimate the cost to decommission the plant and dispose of low level nuclear waste accumulation to range from $634 million to $988 million in 1993 dollars. By law the Company participates in the DOE's SNF disposal program which is described in Note 4 of the Notes to Consolidated Financial Statements. Decommissioning costs and spent nuclear fuel disposal costs are being recovered from ratepayers. In 1993 the

Indiana and the Michigan commissions approved higher levels of recovery so that the amount currently being recovered is at least at the lower end of the range in the prior decommissioning study. To date $212 million in decommissioning cost has been recovered and accrued. Management intends to seek recovery through the rate-making process of changes in the estimate of decommissioning costs over the remaining plant life.

Nuclear operations are continually reviewed for ways to lessen the growth in operation, maintenance and decommissioning costs. In 1994 Cook Plant achieved a superior rating from the Institute of Nuclear Power Operations, a nuclear industry oversight group, and received improved NRC performance ratings. Additionally, costs related to nuclear refueling outages at the Cook Plant have been reduced significantly in the last two years.

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. Should nuclear losses or liabilities be underinsured or exceed accumulated funds, or should recovery through regulated rates be denied, results of operations and financial condition would be negatively affected. Specific information about nuclear risk management and potential liabilities is discussed in Note 4 of the Notes to Consolidated Financial Statements.

In 1994 the Financial Accounting Standards Board (FASB) added Accounting for Nuclear Decommissioning Liabilities to its agenda. Among the topics to be studied by the FASB is the question of when future decommissioning liabilities should be recognized. The Company and the electric utility industry accrue such costs over the service life of their nuclear facilities as recovered in rates. A new requirement from the FASB could cause the annual provisions for decommissioning to increase should the estimate of the remaining unaccrued decommissioning costs be greater than the regulators' allowed recovery level. Management believes that the industry's life of the plant accrual accounting method is appropriate and should be accepted by the FASB. Until the FASB completes its study and reaches a conclusion, the impact, if any, on results of operations and financial condition cannot be determined.

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 resolution of these matters will have a material adverse effect on financial condition. Information about these matters can be found in the footnotes to the financial statements.

Effects of Inflation

Inflation affects the cost of replacing utility plant and the cost of operating and maintaining such plant. The rate-making process generally limits recovery to the historical cost of assets resulting in economic losses when inflation effects 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.

INDEPENDENT AUDITORS' REPORT

To the Shareowners 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, 1994 and 1993, and the related consolidated statements of income, retained earnings, and cash flows for each of the three years in the period ended December 31, 1994. 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, 1994 and 1993, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1994 in conformity with generally accepted accounting principles.

Deloitte & Touche LLP

DELOITTE & TOUCHE LLP
Columbus, Ohio

February 21, 1995

Consolidated Statements of Income

	Year Ended December 31,		
	1994	1993	1992
		(in thousands)	
OPERATING REVENUES	$1,251,309	$1,202,643	$1,196,755
OPERATING EXPENSES:			
Fuel	201,739	220,206	193,830
Purchased Power	131,234	108,274	180,365
Other Operation	293,024	264,543	251,897
Maintenance	139,423	142,637	137,787
Depreciation and Amortization	136,244	138,794	133,365
Amortization of Rockport Plant Unit 1 Phase-in Plan Deferrals	15,644	15,644	16,303
Taxes Other Than Federal Income Taxes	71,191	67,918	62,189
Federal Income Taxes	41,079	34,707	25,499
Total Operating Expenses	1,029,578	992,723	1,001,235
OPERATING INCOME	221,731	209,920	195,520
NONOPERATING INCOME (LOSS)	7,428	(234)	14,115
INCOME BEFORE INTEREST CHARGES	229,159	209,686	209,635
INTEREST CHARGES	71,688	80,373	85,687
NET INCOME	157,471	129,313	123,948
PREFERRED STOCK DIVIDEND REQUIREMENTS	11,650	14,225	15,417
EARNINGS APPLICABLE TO COMMON STOCK	$ 145,821	$ 115,088	$ 108,531

See Notes to Consolidated Financial Statements.

Consolidated Balance Sheets

	December 31,	
	1994	1993
	(in thousands)	
ASSETS		
ELECTRIC UTILITY PLANT:		
Production	$2,494,834	$2,602,527
Transmission	849,920	839,198
Distribution	644,720	608,752
General (including nuclear fuel)	204,909	152,470
Construction Work in Progress	74,923	88,010
Total Electric Utility Plant	4,269,306	4,290,957
Accumulated Depreciation and Amortization	1,659,940	1,714,829
NET ELECTRIC UTILITY PLANT	2,609,366	2,576,128
NUCLEAR DECOMMISSIONING AND SPENT NUCLEAR FUEL DISPOSAL TRUST FUNDS	341,089	300,671
OTHER PROPERTY AND INVESTMENTS	127,424	131,788
CURRENT ASSETS:		
Cash and Cash Equivalents	9,907	3,752
Accounts Receivable:		
Customers	74,491	67,246
Affiliated Companies	24,848	24,507
Miscellaneous	32,714	30,087
Allowance for Uncollectible Accounts	(121)	(504)
Fuel - at average cost	35,802	34,476
Materials and Supplies - at average cost	59,897	57,800
Accrued Utility Revenues	40,582	34,642
Prepayments	8,414	12,043
TOTAL CURRENT ASSETS	286,534	264,049
REGULATORY ASSETS	481,212	441,681
DEFERRED CHARGES	70,104	51,141
TOTAL	$3,915,729	$3,765,458

See Notes to Consolidated Financial Statements.

	December 31, 1994	December 31, 1993
	(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	734,511	734,933
Retained Earnings	216,658	177,638
Total Common Shareholder's Equity	1,007,753	969,155
Cumulative Preferred Stock:		
Not Subject to Mandatory Redemption	52,000	87,000
Subject to Mandatory Redemption	135,000	100,000
Long-term Debt	929,887	1,073,154
TOTAL CAPITALIZATION	2,124,640	2,229,309
OTHER NONCURRENT LIABILITIES:		
Nuclear Decommissioning	211,963	169,706
Other	170,346	118,491
TOTAL OTHER NONCURRENT LIABILITIES	382,309	288,197
CURRENT LIABILITIES:		
Long-term Debt Due Within One Year	140,000	-
Short-term Debt - Commercial Paper	50,600	50,075
Accounts Payable - General	40,417	40,437
Accounts Payable - Affiliated Companies	22,720	17,481
Taxes Accrued	63,621	54,473
Interest Accrued	19,436	18,894
Obligations Under Capital Leases	39,003	20,585
Other	87,821	79,367
TOTAL CURRENT LIABILITIES	463,618	281,312
DEFERRED FEDERAL INCOME TAXES	563,654	553,920
DEFERRED INVESTMENT TAX CREDITS	171,688	186,032
DEFERRED GAIN ON SALE AND LEASEBACK - ROCKPORT PLANT UNIT 2	204,138	211,446
DEFERRED CREDITS	5,682	15,242
COMMITMENTS AND CONTINGENCIES (Note 4)		
TOTAL	$3,915,729	$3,765,458

Consolidated Statements of Cash Flows

	Year Ended December 31,		
	1994	1993	1992
		(in thousands)	
OPERATING ACTIVITIES:			
Net Income	$ 157,471	$ 129,313	$ 123,948
Adjustments for Noncash Items:			
Depreciation and Amortization	146,966	148,270	141,453
Amortization of Rockport Plant Unit 1 Phase-in Plan Deferrals	15,644	15,644	16,303
Amortization (Deferral) of Incremental Nuclear Refueling Outage Expenses (net)	(18,779)	33,827	(47,200)
Deferred Federal Income Taxes	(17,049)	(49,905)	29,897
Deferred Investment Tax Credits	(13,877)	(8,543)	(9,673)
Changes in Certain Current Assets and Liabilities:			
Accounts Receivable (net)	(10,596)	13,102	(7,432)
Fuel, Materials and Supplies	(3,423)	14,938	1,018
Accrued Utility Revenues	(5,940)	43,913	(41,068)
Accounts Payable	5,219	8,233	(15,088)
Taxes Accrued	9,148	38,644	4,514
Other (net)	(11,444)	(17,064)	(16,448)
Net Cash Flows From Operating Activities	253,340	370,372	180,224
INVESTING ACTIVITIES:			
Construction Expenditures	(118,094)	(108,867)	(125,908)
Proceeds from Sales of Property and Other	2,038	5,385	903
Net Cash Flows Used For Investing Activities	(116,056)	(103,482)	(125,005)
FINANCING ACTIVITIES:			
Capital Contributions from Parent Company	-	10,000	-
Issuance of Cumulative Preferred Stock	34,618	98,776	-
Issuance of Long-term Debt	89,221	243,426	271,722
Retirement of Cumulative Preferred Stock	(35,798)	(112,300)	-
Retirement of Long-term Debt	(101,833)	(392,093)	(203,185)
Change in Short-term Debt (net)	525	5,875	(6,750)
Dividends Paid on Common Stock	(106,608)	(108,696)	(106,465)
Dividends Paid on Cumulative Preferred Stock	(11,254)	(15,585)	(15,417)
Net Cash Flows Used For Financing Activities	(131,129)	(270,597)	(60,095)
Net Increase (Decrease) in Cash and Cash Equivalents	6,155	(3,707)	(4,876)
Cash and Cash Equivalents January 1	3,752	7,459	12,335
Cash and Cash Equivalents December 31	$ 9,907	$ 3,752	$ 7,459

See Notes to Consolidated Financial Statements.

Consolidated Statements of Retained Earnings

	Year Ended December 31,		
	1994	1993	1992
		(in thousands)	
Retained Earnings January 1	$177,638	$171,309	$169,243
Net Income	157,471	129,313	123,948
	335,109	300,622	293,191
Deductions:			
Cash Dividends Declared:			
Common Stock	106,608	108,696	106,465
Cumulative Preferred Stock:			
4-1/8% Series	495	495	495
4.56% Series	273	273	273
4.12% Series	165	165	165
5.90% Series	2,360	374	-
6-1/4% Series	1,875	161	-
6.30% Series	1,978	-	-
6-7/8% Series	2,063	1,799	-
7.08% Series	2,124	2,124	2,124
7.76% Series	317	2,716	2,716
8.68% Series	-	2,517	2,604
$2.15 Series	-	3,001	3,440
$2.25 Series	-	600	3,600
Total Cash Dividends Declared	118,258	122,921	121,882
Capital Stock Expense	193	63	-
Total Deductions	118,451	122,984	121,882
Retained Earnings December 31	$216,658	$177,638	$171,309

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, purchase, transmission and distribution of electric power in northern and eastern Indiana and a portion of southwestern Michigan. As a member of the American Electric Power (AEP) System Power Pool (Power Pool) and a signatory company to the AEP 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, Blackhawk Coal Company and Price River Coal Company, that were formerly engaged in coal-mining operations. 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 member of the AEP System, 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 rate regulated. In accordance with Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation*, regulatory assets and liabilities are recorded and represent regulator-approved deferred expenses or revenues, respectively, resulting from the rate-making process. Such deferrals are amortized commensurate with their inclusion in rates (revenues).

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 with regulator approval 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 average rates used to accrue AFUDC were 8.0% in 1994, 8.75% in 1993 and 9.25% in 1992 and the amounts of AFUDC accrued were $3.4 million, $1.7 million and $3.8 million in 1994, 1993 and 1992, respectively.

Depreciation and Amortization

Depreciation 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	Composite Annual Rates
Production:	
Steam-Nuclear	3.4%
Steam-Fossil-Fired	4.3%
Hydroelectric-Conventional	3.0%
Transmission	1.9%
Distribution	4.2%
General	3.8%

Amounts to be used for 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 4.

Cash and Cash Equivalents

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

Operating Revenues

Revenues include the accrual of electricity consumed but unbilled at month-end as well as billed revenues.

Fuel Costs

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 for amortization over the period (generally eighteen months) beginning with the commencement of an outage until the beginning of the next outage.

Income Taxes

The Company follows the liability method of accounting for income taxes as prescribed by SFAS 109, *Accounting for Income Taxes*. Under the liability method, deferred income taxes are provided for all temporary differences between 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, regulatory assets and liabilities are recorded in accordance with SFAS 71.

Investment Tax Credits

Based on directives of regulatory commissions, the Company reflected investment tax credits in rates 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 non-utility property was to practice the flow-through method of accounting.

Debt and Preferred Stock

Gains and losses on reacquired 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 debt issuance expenses are amortized over the term of the related debt, with the amortization included in interest charges.

Redemption premiums paid to reacquire preferred stock are deferred and amortized in accordance with rate-making treatment. The excess of par value over costs of preferred stock reacquired to meet sinking fund requirements is credited to paid-in capital.

Nuclear Decommissioning and Spent Nuclear Fuel Disposal Trust Funds

Investments held in trust funds for decommissioning nuclear facilities and for the disposal of spent nuclear fuel are recorded at market value effective January 1, 1994. Previously such investments were recorded at cost. Adjustments for unrealized gains and losses to the carrying value of trust fund investments are not reflected in equity due to the rate-making process. Instead the unrealized gains and losses are recorded as regulatory assets and liabilities.

Other Property and Investments

Other property and investments are stated at cost.

Reclassifications

Certain prior-period amounts were reclassified to conform with current-period presentation.

2. EFFECTS OF REGULATION AND PHASE-IN PLANS:

The consolidated financial statements include assets and liabilities recorded in accordance with regulatory actions to match expenses and revenues in 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 rate recoveries. The Company's regulatory assets and liabilities are comprised of the following:

	December 31,	
	1994	1993
	(in thousands)	
Regulatory Assets:		
Amounts Due From Customers for Future Federal Income Taxes	$313,731	$286,948
Department of Energy Decontamination and Decommissioning Assessment	51,896	37,086
Rate Phase-in Plan Deferrals	43,159	58,803
Nuclear Refueling Outage Cost Levelization	32,151	13,372
Unamortized Loss On Reacquired Debt	18,472	17,251
Other	21,803	28,221
Total Regulatory Assets	$481,212	$441,681
Regulatory Liabilities:		
Deferred Investment Tax Credits	$171,688	$186,032
Other Regulatory Liabilities*	350	158
Total Regulatory Liabilities	$172,038	$186,190

* Included in Deferred Credits on Consolidated Balance Sheets.

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 for its share of Rockport 1 provide for the recovery and straight-line amortization through 1997 of prior-year deferrals.

3. RATE MATTERS:

Unaffiliated Coal and Affiliated Transportation Cost Recovery

In October 1993, the FERC denied a request by a wholesale customer seeking rehearing of a February 1993 order. The order concerned the reasonableness of coal costs from an unaffiliated supplier who leases a Utah mining operation from the Company and affiliated coal transportation charges. The February order reversed an administrative law judge's decision and dismissed the complaint. The wholesale customer appealed the October order to the U.S. Court of Appeals. It is not anticipated that the ultimate resolution of this matter will have a material adverse impact on results of operations.

4. COMMITMENTS AND CONTINGENCIES:

Construction and Other Commitments

Substantial construction commitments have been made. Such commitments do not include any expenditures for new generating capacity. The aggregate construction program expenditures for 1995-1997 are estimated to be $393 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.

Unit Power Agreements

The Company is committed under unit power agreements to purchase 70% of AEGCo's 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 Rockport Plant capacity to an unaffiliated utility. The contract expires in 2009.

Litigation

An appeal to the Indiana Court of Appeals by a local distribution utility of a 1992 DeKalb County Circuit Court of Indiana decision is pending. Oral arguments before the Indiana Court of Appeals were held in January 1995. The circuit court had dismissed the case filed under a provision of Indiana law that allows the local distribution utility to seek damages equal to the gross revenues received by the Company for rendering service in the designated service territory of the local distribution utility. The Company had received approximately $29 million in gross revenues from a major industrial customer in the local distribution utility's service territory. The case resulted from a Supreme Court of Indiana decision which overruled an appeals court and voided an IURC order which assigned the major industrial customer to the Company.

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

Clean Air

The Clean Air Act Amendments of 1990 (CAAA) require significant reductions in sulfur dioxide and nitrogen oxide emissions from various AEP System generating plants. The first phase of reductions in sulfur dioxide emissions (Phase I) began on January 1, 1995 and the second, more restrictive phase (Phase II) begins on January 1, 2000. The law also established a permanent nationwide cap on sulfur dioxide emissions after 1999.

The AEP Systemwide compliance plan calls for fuel switching to medium-sulfur coal at the Company's Tanners Creek Unit 4 with minimal capital cost. The Breed unit which is a Phase I affected unit was closed in 1994. The Company's other generating units are not affected in Phase I.

The Company will incur additional costs to comply with Phase II requirements at its generating plants. In addition, a portion of the costs of compliance for the AEP System may be incurred through the Power Pool (which is described in Note 8). If the Company is unable to recover its compliance costs from its customers, results of operations would be adversely impacted.

Other Environmental Matters

The Company and its subsidiaries are regulated by federal, state and local authorities with respect to air and water quality and other environmental matters. Local authorities also regulate zoning. The generation of electricity produces non-hazardous and hazardous by-products. Asbestos, polychlorinated biphenyls (PCBs) and other hazardous materials have been used in the generating plants and transmission/distribution facilities. Substantial costs to store and dispose of hazardous and non-hazardous materials have been incurred. Significant additional costs could be incurred in the future to meet the requirements of new laws and regulations and to clean up disposal sites under existing legislation. Management has no knowledge of any material clean up costs related to the Company's past disposal of hazardous and non-hazardous materials.

Nuclear Plant

I&M owns and operates the two-unit 2,110 mw Cook Plant under licenses granted by a regulatory authority. 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. Should nuclear losses or liabilities be underinsured or exceed accumulated funds, or should recovery through regulated rates be denied, results of operations and financial condition would be negatively affected. Specific information about nuclear risk management and potential liabilities is discussed below.

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 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 $41.9 million 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 $154 million for fuel consumed prior to April 7, 1983 have been recorded as long-term debt with an offsetting regulatory asset. The regulatory asset at December 31, 1994 of $8.4 million is being amortized as rate recovery occurs. I&M has not paid the government the pre-April 1983 fees due to various factors including continued delays and uncertainties related to the federal disposal program. At December 31, 1994, funds collected from customers and related earnings including accrued interest totaled $145.6 million.

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. Estimated decommissioning and low level radioactive waste accumulation disposal costs range from $634 million to $988 million in 1993 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 which depends on future developments in the federal government's spent nuclear fuel disposal program. Decommissioning costs are being recovered in the 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 decommissioning liability equal to the decommissioning cost recovered in rates which was $26 million in 1994, $13 million in 1993 and $12 million in 1992. Decommissioning amounts recovered from customers are deposited in external trusts. Trust fund earnings increase the fund assets and the recorded liability. Trust fund earnings decrease the amount to be recovered from ratepayers. At December 31, 1994 the Company has recognized a decommissioning liability of $212 million.

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 contribution required by the Employee Retirement Income Security Act of 1974.

Net pension costs for the years ended December 31, 1994, 1993 and 1992 were $5 million, $4.7 million and $5.6 million, respectively.

An employee savings plan is offered which allows participants to contribute up to 17% of their salaries into three 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 $3.9 million in 1994, $3.5 million in 1993 and $3.3 million in 1992.

Certain other benefits are provided for retired employees under an AEP System other postretirement benefit plan. Substantially all employees are eligible for postretirement health care and life

insurance if they have at least 10 service years and are age 55 at retirement. Prior to 1993, net costs of these benefits were recognized as an expense when paid and totaled $2.7 million in 1992.

SFAS 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions*, was adopted in January 1993 for the Company's aggregate liability for postretirement benefits other than pensions (OPEB). SFAS 106 requires the accrual during the employee's service years of the present value liability for OPEB costs. Costs for the accumulated postretirement benefits earned and not recognized at adoption are being recognized, in accordance with SFAS 106, as a transition obligation over 20 years. OPEB costs are determined by the application of AEP System actuarial assumptions to each operating company's employee complement. The annual accrued OPEB costs for employees and retirees required by SFAS 106, which includes the recognition of one-twentieth of the prior service transition obligation, were $13.2 million in 1994 and $12.4 million in 1993.

The Company received approval from the IURC to recover the increased OPEB costs resulting from SFAS 106. In the Michigan and wholesale jurisdictions, the Company received authority to defer the increased OPEB costs which are not being currently recovered in rates. Future recovery of the deferrals and the annual ongoing increased OPEB costs will be sought in the next base rate filings. At December 31, 1994, $6.7 million of incremental OPEB costs were deferred.

A Voluntary Employees Beneficiary Association (VEBA) trust fund for OPEB benefits was established and a corporate owned life insurance (COLI) program was implemented. The insurance policies have a substantial cash surrender value which is recorded, net of equally substantial policy loans, as other property and investments. For the Indiana jurisdiction where OPEB costs are reflected in cost of service, the amount contributed to the VEBA trust fund is the difference between the pay-as-you-go OPEB cost and the SFAS 106 total OPEB cost. This contribution is funded by amounts collected from ratepayers plus net earnings from the COLI program. For FERC and Michigan jurisdictions where recovery has not been approved and rates are insufficient to absorb these additional costs, the contribution to the VEBA trust fund is the cash generated by the COLI program. Contributions to the VEBA trust fund were $6.6 million in 1994 and $1.3 million in 1993.

6. SUPPLEMENTARY INFORMATION:

	Year Ended December 31,		
	1994	1993	1992
		(in thousands)	
Cash was paid for:			
Interest (net of capitalized amounts)	$68,946	$82,509	$84,691
Income Taxes	85,854	68,303	15,285
Noncash Acquisitions Under Capital Leases were	92,199	15,467	47,905

7. FEDERAL INCOME TAXES:

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

	Year Ended December 31,		
	1994	1993 (in thousands)	1992
Charged (Credited) to Operating Expenses (net):			
Current	$ 64,565	$ 93,974	$ 9,122
Deferred	(15,331)	(50,959)	25,405
Deferred Investment Tax Credits	(8,155)	(8,308)	(9,028)
Total	41,079	34,707	25,499
Charged (Credited) to Nonoperating Income (net):			
Current	1,390	6,026	1,569
Deferred	(1,718)	1,054	4,492
Deferred Investment Tax Credits	(5,722)	(235)	(645)
Total	(6,050)	6,845	5,416
Total Federal Income Taxes as Reported	$ 35,029	$ 41,552	$30,915

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,		
	1994	1993 (in thousands)	1992
Net Income	$157,471	$129,313	$123,948
Federal Income Taxes	35,029	41,552	30,915
Pre-tax Book Income	$192,500	$170,865	$154,863
Federal Income Tax on Pre-tax Book Income at Statutory Rate (35% in 1994 and 1993; 34% in 1992)	$ 67,375	$59,803	$52,653
Increase (Decrease) in Federal Income Tax Resulting From the Following Items:			
Removal Costs	(2,422)	(2,632)	(3,042)
Adoption of SFAS 109	-	5,271	-
Corporate Owned Life Insurance	(4,521)	(4,697)	(4,402)
Nuclear Fuel Disposal Costs	(4,498)	(2,432)	(2,068)
Investment Tax Credits (net)	(13,875)	(8,543)	(9,011)
Other	(7,030)	(5,218)	(3,215)
Total Federal Income Taxes as Reported	$ 35,029	$41,552	$30,915
Effective Federal Income Tax Rate	18.2%	24.3%	20.0%

The following tables show the elements of the net deferred tax liability and the significant temporary differences that gave rise to it:

	December 31, 1994	December 31, 1993
	(in thousands)	
Deferred Tax Assets	$ 235,165	$ 233,380
Deferred Tax Liabilities	(798,819)	(787,300)
Net Deferred Tax Liabilities	$(563,654)	$(553,920)
Property Related Temporary Differences	$(498,124)	$(494,966)
Amounts Due From Customers For Future Federal Income Taxes	(109,806)	(100,432)
Deferred Net Gain - Rockport Plant Unit 2	60,561	62,761
All Other (net)	(16,285)	(21,283)
Total Net Deferred Tax Liabilities	$(563,654)	$(553,920)

The Company and its subsidiaries join in the filing of a consolidated federal income tax return with their affiliates in the AEP System. The allocation of the AEP System's current consolidated federal income tax to the 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 System parent company, AEP Co., Inc., is allocated to its subsidiaries with taxable income. With the exception of the loss of the 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 1988. Returns for the years 1988 through 1990 are presently being audited by the IRS. In the opinion of management, the final settlement of open years will not have a material effect on results of operations.

8: RELATED PARTY TRANSACTIONS:

Benefits and costs of the System's generating plants are shared by members of the Power Pool. Under the terms of the System Interconnection Agreement, capacity charges and credits are designed to allocate the cost of the 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.

Operating revenues include $140.5 million in 1994, $204.6 million in 1993 and $154.1 million in 1992 for energy and capacity supplied to the Power Pool. Purchased power expense includes charges of $33.1 million in 1994, $20.9 million in 1993 and $82.6 million in 1992 for energy received from the Power Pool.

Power Pool members share in wholesale sales to unaffiliated utilities made by the Power Pool. The Company's share of the Power Pool wholesale sales included in operating revenues were $54.1 million in 1994, $57 million in 1993 and $45.8 million in 1992.

In addition, the Power Pool purchases power from unaffiliated companies for immediate resale to other unaffiliated utilities. The Company's share of these purchases was included in purchased power expense and totaled $14.2 million in 1994, $5.1 million in 1993 and $6.5 million in 1992. Revenues from these transactions are included in the above Power Pool wholesale operating revenues.

The cost of 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 $82.4 million, $78.9 million and $88 million in 1994, 1993 and 1992, 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 System companies' respective peak demands. Pursuant to the terms of the agreement, equalization credits of $50.3 million, $47.4 million and $48.2 million were recorded in other operation expense in 1994, 1993 and 1992, respectively.

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

	Year Ended December 31,		
	1994	1993	1992
	(in thousands)		
Affiliated Companies	$24,001	$21,332	$20,154
Unaffiliated Companies	5,021	5,757	8,563
Total	$29,022	$27,089	$28,717

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.

9. FAIR VALUE OF FINANCIAL INSTRUMENTS:

Nuclear Trust Funds Recorded at Market Value

Effective January 1, 1994, the Company adopted SFAS 115, *Accounting for Certain Investments in Debt and Equity Securities,* which requires fair value accounting for investments in equity securities with readily determinable market values and investments in debt securities except those that the reporting enterprise has the positive intent and ability to hold to maturity. Debt securities not classified as held-to-maturity and qualifying equity securities, shall be classified as trading or available-for-sale. The Company's investments held in trust funds for decommissioning nuclear facilities and for disposal of spent nuclear fuel have been classified as available-for-sale. SFAS 115 requires that unrealized gains and losses on investments classified as available-for-sale be reported as a separate component of shareholder's equity. However, due to the rate-making process, adjustments under SFAS 115 for unrealized gains and losses to the carrying value of investments held in the trusts result in corresponding adjustments to regulatory assets and liabilities.

The cumulative effect of adopting SFAS 115 resulted in an increase in the decommissioning and spent nuclear fuel trust fund assets of $20.4 million comprised of an unrealized holding gain of $21.4 million and an unrealized holding loss of $1.0 million, with no effect on net income and/or shareholder's equity. The trust investments, reported in other property and investments, had a fair value of $321 million at January 1, 1994 and consisted primarily of tax-exempt municipal bonds. In accordance with SFAS 115, prior year amounts were not restated.

At December 31, 1994, the fair value of the trust investments was $353 million. Accumulated gross unrealized holding gains and losses were $5.5 million and $12.2 million, respectively, at December 31, 1994. The change in market value during 1994 was a $27.1 million net holding loss.

The trust investments' cost basis by security type at December 31, 1994 was:

	(in thousands)
Treasury bonds	$ 997
Tax-exempt bonds	332,098
Equity securities	1,665
Cash and cash equivalents	25,304
Total	$360,064

Proceeds from sales and maturities of securities were $20.1 million during 1994 which resulted in $52,000 of realized gains and $155,000 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, 1994, the year of maturity of trust fund investments, other than equity securities, was:

	(in thousands)
1995	$ 39,173
1996-1999	85,199
2000-2004	142,868
After 2004	91,159
Total	$358,399

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 $117 million and $99 million and for long-term debt were $1.0 billion and $1.1 billion at December 31, 1994 and 1993, respectively.

The carrying amounts for preferred stock subject to mandatory redemption were $135 million and $100 million and for long-term debt were $1.1 billion and $1.1 billion at December 31, 1994 and 1993, 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 pre-April 1983 spent nuclear fuel disposal liability approximates the Company's best estimate of its fair value.

10. 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.

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

	December 31, 1994	1993
	(in thousands)	
Electric Utility Plant:		
Production	$ 8,371	$ 8,033
Distribution	14,717	14,717
General:		
Nuclear Fuel (net of amortization)	89,478	45,661
Other	53,781	48,418
Total Electric Utility Plant	166,347	116,829
Accumulated Amortization	27,225	27,359
Net Electric Utility Plant	139,122	89,470
Other Property	15,842	11,269
Accumulated Amortization	2,375	1,986
Net Other Property	13,467	9,283
Net Properties under Capital Lease	$152,589	$ 98,753
Capital Lease Obligations:		
Noncurrent Liability	$113,586	$78,168
Liability Due Within One Year	39,003	20,585
Total Capital Lease Obligations	$152,589	$98,753

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

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

	Year Ended December 31, 1994	1993	1992
		(in thousands)	
Operating Leases	$104,519	$103,884	$109,466
Amortization of Capital Leases	30,875	46,063	24,124
Interest on Capital Leases	7,643	8,873	7,473
Total Rental Costs	$143,037	$158,820	$141,063

Future minimum lease payments consisted of the following at December 31, 1994:

	Capital Leases	Non-Cancelable Operating Leases
	(in thousands)	
1995	$ 11,558	$ 97,725
1996	10,370	97,579
1997	9,262	95,772
1998	8,299	90,631
1999	7,171	90,489
Later Years	40,570	1,919,552
Total Future Minimum Lease Payments	87,230(a)	$2,391,748
Less Estimated Interest Element	24,119	
Estimated Present Value of Future Minimum Lease Payments	63,111	
Unamortized Nuclear Fuel	89,478	
Total	$152,589	

(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.

11. CUMULATIVE PREFERRED STOCK:

At December 31, 1994, 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 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 1993 the Company redeemed and cancelled the following entire series: 8.68% series consisting of 300,000 shares and $2.15 and $2.25 series each consisting of 1,600,000 shares.

A. Cumulative Preferred Stock Not Subject to Mandatory Redemption:

Series	Call Price December 31, 1994	Par Value	Number of Shares Redeemed Year Ended December 31,			Shares Outstanding December 31, 1994	Amount December 31, (in thousands)	
			1994	1993	1992		1994	1993
4-1/8%	$106.125	$100	-	-	-	120,000	$ 12,000	$ 12,000
4.56%	102	100	-	-	-	60,000	6,000	6,000
4.12%	102.728	100	-	-	-	40,000	4,000	4,000
7.08%	101.85	100	-	-	-	300,000	30,000	30,000
7.76%	-	-	350,000	-	-	-	-	35,000
							$ 52,000	$ 87,000

B. Cumulative Preferred Stock Subject to Mandatory Redemption:

Series(a)	Par Value	Shares Outstanding December 31, 1994	Amount December 31, (in thousands)	
			1994	1993
5.90% (b)	$100	400,000	$ 40,000	$ 40,000
6-1/4%(c)	100	300,000	30,000	30,000
6.30% (d)	100	350,000	35,000	-
6-7/8%(e)	100	300,000	30,000	30,000
			$135,000	$100,000

(a) Not callable until after 2002. There are no aggregate sinking fund provisions through 2002.
(b) Shares issued November 1993. Commencing in 2004 and continuing through the year 2008, a sinking fund will require the redemption of 20,000 shares each year and the redemption of the remaining shares outstanding on January 1, 2009, in each case at $100 per share.
(c) Shares issued November 1993. Commencing in 2004 and continuing through the year 2008, a sinking fund will require the redemption of 15,000 shares each year and the redemption of the remaining shares outstanding on April 1, 2009, in each case at $100 per share.
(d) Shares issued February 1994. Commencing in 2004 and continuing through the year 2008, a sinking fund will require the redemption of 17,500 shares each year and the redemption of the remaining shares outstanding on July 1, 2009, in each case at $100 per share.
(e) Shares issued February 1993. 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.

12. LONG-TERM DEBT AND LINES OF CREDIT:

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

	December 31, 1994	December 31, 1993
	(in thousands)	
First Mortgage Bonds	$ 561,770	$ 571,468
Installment Purchase Contracts	308,087	307,823
Other Long-term Debt (a)	153,977	147,810
Notes Payable to Banks	40,000	40,000
Sinking Fund Debentures	6,053	6,053
	1,069,887	1,073,154
Less Portion Due Within One Year	140,000	-
Total	$ 929,887	$1,073,154

(a) Nuclear Fuel Disposal Costs including interest accrued. See Note 4.

First mortgage bonds outstanding were as follows:

% Rate	Due	December 31, 1994	December 31, 1993
		(in thousands)	
7	1998 - May 1	$ 35,000	$ 35,000
7.30	1999 - December 15	35,000	35,000
7.63	2001 - June 1	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	-
8-3/4	2017 - February 1	-	100,000
9.50	2021 - May 1	10,000	10,000
9.50	2021 - May 1	10,000	10,000
9.50	2021 - May 1	20,000	20,000
8.75	2022 - May 1	50,000	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	-
Unamortized Discount (net)		(3,230)	(3,532)
Total		$561,770	$571,468

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, 1994	December 31, 1993
		(in thousands)	
City of Lawrenceburg, Indiana:			
7	2015 - April 1	$ 25,000	$ 25,000
5.9	2019 - November 1	52,000	52,000
City of Rockport, Indiana:			
9-1/4	2014 - August 1	50,000	50,000
6-3/4(a)	2014 - August 1	50,000	50,000
(b)	2014 - August 1	50,000	50,000
7.6	2016 - March 1	40,000	40,000
City of Sullivan, Indiana:			
5.95	2009 - May 1	45,000	45,000
Unamortized Discount		(3,913)	(4,177)
		308,087	307,823
Less Portion Due Within One Year		100,000	-
Total		$208,087	$307,823

(a) The adjustable interest rate will change on August 1, 1995.
(b) The variable interest rate is determined weekly. The average weighted interest was 3.8% for 1994 and 3.0% for 1993.

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 certain series the principal is payable at stated maturities or on the demand of the bondholders at periodic interest adjustment dates. Certain series are supported by bank letters of credit which expire in 1995. As a result these series are classified as due within one year on the December 31, 1994 Consolidated Balance Sheet.

A $40 million unsecured promissory note payable to a bank is due November 19, 1995 at an annual interest rate of 9.07%.

The sinking fund debentures are due May 1, 1998 at an interest rate of 7-1/4%. Prior to December 31, 1994, sufficient principal amounts of debentures had been reacquired in anticipation of all future sinking fund requirements. Additional debentures of up to $300,000 may be called annually.

At December 31, 1994, annual long-term debt payments, excluding premium or discount, are as follows:

	Principal Amount (in thousands)
1995	$ 140,000
1996	-
1997	-
1998	41,053
1999	35,000
Later Years	860,977
Total	$1,077,030

Short-term debt borrowings are limited by provisions of the 1935 Act to $200 million and further limited by charter provisions to $130 million. Lines of credit are shared with AEP System companies and at December 31, 1994 and 1993 were available in the amounts of $558 million and $537 million, respectively. Commitment fees of approximately 3/16 of 1% of the unused short-term lines of credit are paid each year to the banks to maintain the lines of credit. Outstanding short-term debt consisted of commercial paper as follows:

	Balance Outstanding (in thousands)	Weighted Average Interest Rate
December 31, 1994	$50,600	6.3%
December 31, 1993	50,075	3.6

13. COMMON SHAREOWNER'S EQUITY:

Mortgage indentures, debentures, 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, 1994, $5.9 million of retained earnings were restricted. Regulatory approval is required to pay dividends out of paid-in capital.

In 1994 paid-in capital was charged $422,000 for costs associated with issuing and redeeming cumulative preferred stock. In 1993 I&M's parent made a cash capital contribution of $10 million and a charge of $1.2 million for the issuance of three series of cumulative preferred stock was recorded to paid-in capital. There were no other transactions affecting the common stock or paid-in capital accounts in 1994, 1993 and 1992.

14. UNAUDITED QUARTERLY FINANCIAL INFORMATION:

Quarterly Periods Ended	Operating Revenues	Operating Income	Net Income
	(in thousands)		
1994			
March 31	$337,921	$58,815	$44,968
June 30	310,104	54,632	37,274
September 30	317,061	55,409	37,728
December 31	286,223	52,875	37,501
1993			
March 31	302,968	53,269	28,522
June 30	278,100	40,722	21,397
September 30	320,409	52,898	33,658
December 31	301,166	63,031	45,736

OPERATING STATISTICS

	1994	1993	1992	1991	1990
OPERATING REVENUES (in thousands):					
Retail:					
Residential:					
Without Electric Heating	$ 227,358	$ 205,315	$ 209,682	$ 206,257	$ 192,822
With Electric Heating	107,523	97,568	98,553	93,289	88,718
Total Residential	334,881	302,883	308,235	299,546	281,540
Commercial	247,938	220,938	228,285	216,303	205,025
Industrial	291,527	250,939	267,643	241,858	244,773
Miscellaneous	6,316	5,593	11,012	12,120	11,799
Total Retail	880,662	780,353	815,175	769,827	743,137
Wholesale (sales for resale)	352,889	404,910	369,379	436,083	518,080
Total Revenues from Energy Sales	1,233,551	1,185,263	1,184,554	1,205,910	1,261,217
Provision for Refunds of Revenues Collected in Prior Years	-	(755)	(4,038)	5,176	(5,176)
Total Net of Provision for Refunds	1,233,551	1,184,508	1,180,516	1,211,086	1,256,041
Other	17,758	18,135	16,239	14,781	15,473
Total Operating Revenues	$1,251,309	$1,202,643	$1,196,755	$1,225,867	$1,271,514
SOURCES AND SALES OF ENERGY (in millions of kilowatt-hours):					
Sources:					
Net Generated:					
Fossil Fuel	13,022	12,236	11,597	12,109	14,451
Nuclear Fuel	9,291	16,313	6,418	15,524	11,115
Hydroelectric	95	106	100	109	127
Total Net Generated	22,408	28,655	18,115	27,742	25,693
Purchased and Power Pool	5,757	4,879	9,342	5,237	7,983
Total Sources	28,165	33,534	27,457	32,979	33,676
Less: Losses, Company Use, Etc.	1,398	1,349	1,466	1,454	1,633
Net Sources	26,767	32,185	25,991	31,525	32,043
Sales:					
Retail:					
Residential:					
Without Electric Heating	3,210	3,178	3,001	3,166	2,955
With Electric Heating	1,727	1,706	1,633	1,625	1,525
Total Residential	4,937	4,884	4,634	4,791	4,480
Commercial	4,148	3,977	3,747	3,726	3,536
Industrial	6,453	6,025	5,685	5,382	5,452
Miscellaneous	82	83	194	233	229
Total Retail	15,620	14,969	14,260	14,132	13,697
Wholesale (sales for resale)	11,147	17,216	11,731	17,393	18,346
Total Sales	26,767	32,185	25,991	31,525	32,043

OPERATING STATISTICS (Concluded)

	1994	1993	1992	1991	1990
AVERAGE COST OF FUEL CONSUMED (in cents):					
Per Million Btu:					
Coal	124	130	136	141	145
Nuclear	42	36	54	48	58
Overall	85	72	103	84	105
Per Kilowatt-hour Generated:					
Coal	1.21	1.27	1.34	1.39	1.42
Nuclear	.47	.40	.61	.53	.64
Overall	.90	.77	1.08	.91	1.08
RESIDENTIAL SERVICE - AVERAGES:					
Annual Kwh Use per Customer:					
With Electric Heating	17,907	17,980	17,513	17,702	16,897
Total	10,572	10,559	10,107	10,535	9,944
Annual Electric Bill:					
With Electric Heating	$1,115.19	$1,028.26	$1,056.91	$1,016.16	$983.28
Total	$717.17	$654.76	$672.31	$658.76	$624.95
Price per Kwh (in cents):					
With Electric Heating	6.23	5.72	6.04	5.74	5.82
Total	6.78	6.20	6.65	6.25	6.28
NUMBER OF CUSTOMERS:					
Year-End:					
Retail:					
Residential:					
Without Electric Heating	372,473	369,385	366,835	364,154	362,645
With Electric Heating	97,402	95,795	94,175	92,657	91,179
Total Residential	469,875	465,180	461,010	456,811	453,824
Commercial	53,927	53,081	52,542	51,491	50,994
Industrial	5,213	5,157	5,000	4,847	4,801
Miscellaneous	1,806	1,783	1,751	2,226	2,160
Total Retail	530,821	525,201	520,303	515,375	511,779
Wholesale (sales for resale)	54	56	53	53	55
Total Customers	530,875	525,257	520,356	515,428	511,834

DIVIDENDS AND PRICE RANGES OF CUMULATIVE PREFERRED STOCK
By Quarters (1994 and 1993)

	1994 - Quarters				1993 - 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	55-5/8	54-1/8	50-5/8	46-1/8	-	-	-	-
- Low	49	45-1/2	45-1/2	45-1/2	-	-	-	-
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	58-1/2	54	48	48	51	51-1/2	55-1/4	58-1/2
- Low	51	46-1/2	46-1/8	43-1/2	48	48	51	54-3/4
5.90% Series (a)								
Dividends Paid Per Share	$1.475	$1.475	$1.475	$1.475				$0.9342
Market Price - $ Per Share (OTC)								
Ask (high/low)	-	-	-	-				-
Bid (high/low)	-	-	-	-				-
6-1/4% Series (a)								
Dividends Paid Per Share	$1.5625	$1.5625	$1.5625	$1.5625				$0.5382
Market Price - $ Per Share (OTC)								
Ask (high/low)	-	-	-	-				-
Bid (high/low)	-	-	-	-				-
6.30% Series (b)								
Dividends Paid Per Share	$0.9275	$1.575	$1.575	$1.575				
Market Price - $ Per Share (OTC)								
Ask (high/low)	-	-	-	-				
Bid (high/low)	-	-	-	-				
6-7/8% Series (c)								
Dividends Paid Per Share	$1.71875	$1.71875	$1.71875	$1.71875	$0.84	$1.71875	$1.71875	$1.71875
Market Price - $ Per Share (OTC)								
Ask (high/low)	-	-	-	-	-	-	-	-
Bid (high/low)	-	-	-	-	-	-	-	-
7.08% Series								
Dividends Paid Per Share	$1.77	$1.77	$1.77	$1.77	$1.77	$1.77	$1.77	$1.77
Market Price - $ Per Share								
(NYSE) - High	97-1/2	95	87-1/2	80	92	96	99-5/8	100-1/8
- Low	94	83	80	76	89-1/4	91	96-3/8	95

DIVIDENDS AND PRICE RANGES OF CUMULATIVE PREFERRED STOCK
By Quarters (1994 and 1993) (Concluded)

	1994 - Quarters				1993 - Quarters			
	1st	2nd	3rd	4th	1st	2nd	3rd	4th
CUMULATIVE PREFERRED STOCK								
7.76% Series (Redeemed)								
Dividends Paid Per Share	$0.9054				$1.94	$1.94	$1.94	$1.94
Market Price - $ Per Share								
(NYSE) - High	101				102-1/4	102	104	102-3/4
- Low	100				95-3/4	98	100	98-1/2
($100 Par Value)								
8.68% Series (Redeemed)								
Dividends Paid Per Share					$2.17	$2.17	$2.17	$1.8807
Market Price - $ Per Share								
(NYSE) - High					103	103-1/2	104	103
- Low					100	101	101	101-1/4
($25 Par Value)								
$2.15 Series (Redeemed)								
Dividends Paid Per Share					$0.5375	$0.5375	$0.5375	$0.2628
Market Price - $ Per Share								
(NYSE) - High					27-1/2	27-1/4	27-3/8	26-1/2
- Low					26	26-1/4	25-3/4	25-5/8
$2.25 Series (Redeemed)								
Dividends Paid Per Share					$0.375			
Market Price - $ Per Share								
(NYSE) - High					26-3/4			
- Low					25-1/2			

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) Issued November 1993
(b) Issued February 1994
(c) Issued February 1993

SECURITY OWNER INQUIRIES

Security owners should direct their inquiries to the Security Owner Relations Division using the toll free number: 1-800-AEP-COMP (1-800-237-2667) or by writing to:

Bette Jo Rozsa
Security Owner Relations Division
American Electric Power Service Corporation
28th Floor
1 Riverside Plaza
Columbus, OH 43215-2373

FORM 10-K ANNUAL REPORT

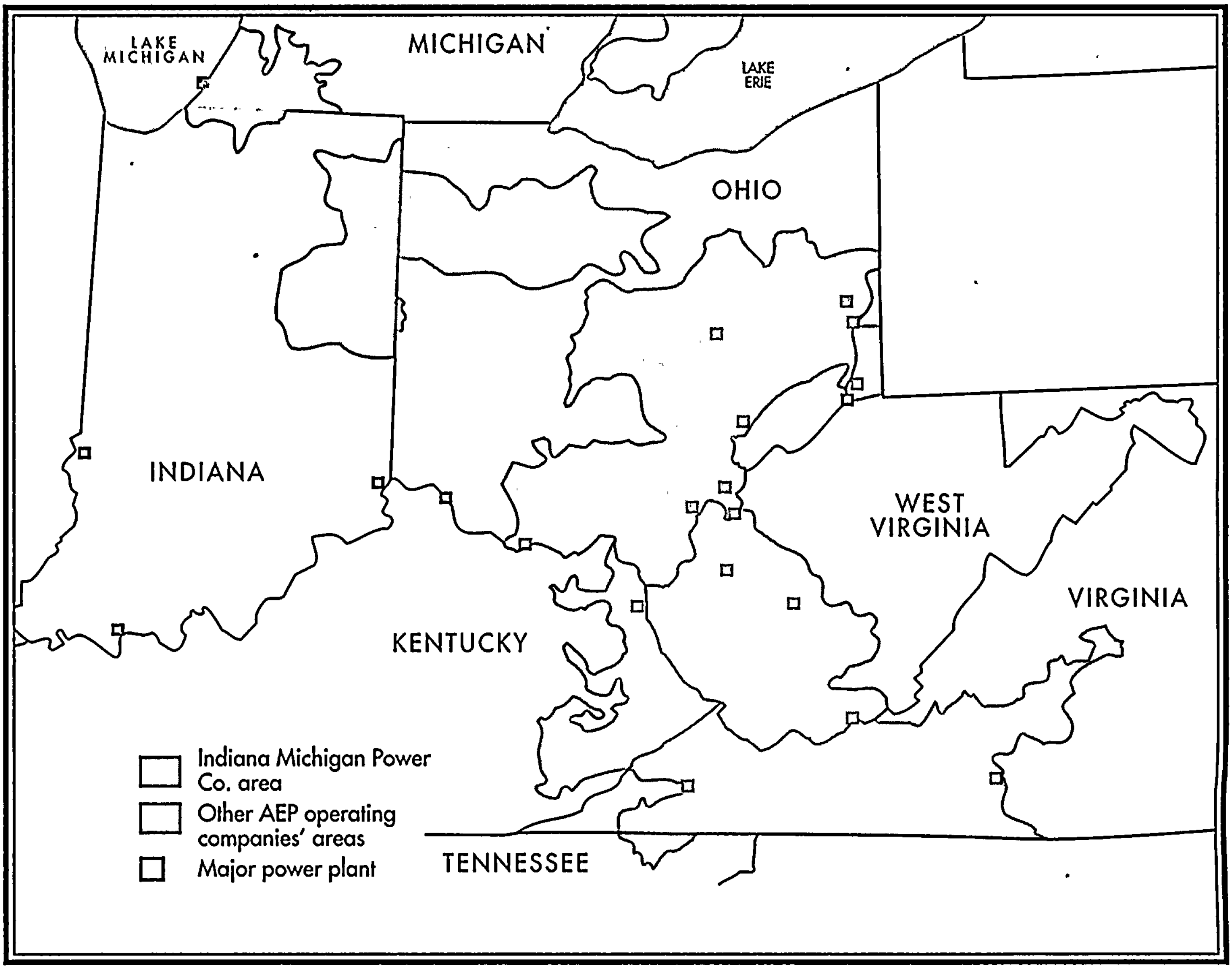
The Annual Report (Form 10-K) to the Securities and Exchange Commission will be available in April 1995 at no cost to shareowners. Please address such requests to:

Geoffrey C. Dean
American Electric Power Service Corporation
27th 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

Indiana Michigan Power Service Area and the American Electric Power System



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ATTACHMENT 2 TO AEP:NRC:0909K

INDIANA MICHIGAN POWER COMPANY'S

PROJECTED CASH FLOW FOR 1995

Indiana Michigan Power Co.
1995 Forecasted Sources and Uses of Funds
Based on Forecasted Case 9501

$ Millions	Projected 1995
Net Income After Taxes	136.4
Less Dividends Paid	122.5
Retained Earnings	13.9
Adjustments:	
Depreciation And Amortization	163.0
Deferred Operating Costs	2.9
Deferred Federal Income Taxes and Investment Tax Credits	(26.4)
AFUDC	(3.1)
Other	7.7
Total Adjustments	144.1
Internal Cash Flow	158.0
Average Quarterly Cash Flow	39.5
Average Cash Balances and Short-Term Investments	8.9
Total	48.4

[illegible]