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Indiana Michigan
Power Company
P.O. Box 16631
Columbus, OH 43216

INDIANA
MICHIGAN
POWER

April 12, 1996 AEP:NRC:0909L

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 annual report for 1995. Attachment 2 contains a copy of I&M's projected cash flow for 1996. These reports are submitted pursuant to 10 CFR 50.71(b) and 10 CFR 140.21(e).

Sincerely,

for W. G. Smith
E. E. Fitzpatrick
Vice President

eh

Attachments

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

150093

A004
1/1

ATTACHMENT 1 TO AEP:NRC:0909L

INDIANA MICHIGAN POWER COMPANY'S

ANNUAL REPORT FOR 1995

Indiana Michigan Power Company

1995 Annual Report

AEP AMERICAN ELECTRIC POWER

ANA MICHIGAN POWER COMPANY
AND SUBSIDIARIES

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

CONTENTS

INDIANA MICHIGAN POWER COMPANY (the Company) is engaged in the generation, purchase, transmission and distribution of electric power. The Company serves approximately 537,000 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, electrical and electronic machinery, transportation equipment, fabricated metal products, rubber and miscellaneous plastic products and chemicals and allied products.

The Company is a subsidiary of American Electric Power Company, Inc., a public utility holding company, and was organized under the laws of Indiana on February 21, 1925. As of January 1, 1996, the Company began doing business as American Electric Power (AEP) along with all of the parent's operating subsidiary companies in order to serve its customers more efficiently as one operating organization realigned by distinct, separately managed generation, energy delivery and non-regulated business groups. 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 owned by the Company and affiliated companies. 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 2,110 mw of nuclear generation. The Company owns the two unit Donald C. Cook Nuclear Plant located in Michigan. The generating plants and transmission facilities of the Company and certain other affiliated AEP System utility subsidiaries are operated as an integrated system with their costs and benefits shared through the AEP System Power Pool and AEP Transmission Agreement. Wholesale energy sales made by the Power Pool are allocated to the 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 that are not members of the Power Pool, and with numerous unaffiliated utilities.

DIRECTORS

Mark A. Bailey (a)
Coulter R. Boyle, III (b)
Gregory A. Clark (c)
Peter J. DeMaria
William N. D'Onofrio

E. Linn Draper, Jr.
William J. Lhota
Gerald P. Maloney
James J. Markowsky
Richard C. Menge (a)

Albert H. Potter
David B. Synowiec (c)
Dale M. Trenary (b)
Joseph H. Vipperman (b)
William E. Walters (b)

OFFICERS

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

William J. Lhota (b)
President and Chief Operating Officer

Richard C. Menge (a)
President and Chief Operating Officer

Mark A. Bailey (a)
Vice President

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

Coulter R. Boyle, III (b)
Vice President

Peter J. DeMaria
Vice President and Controller

William N. D'Onofrio (a)
Vice President

Eugene E. Fitzpatrick
Vice President

Gerald P. Maloney
Vice President

James J. Markowsky
Vice President

Joseph H. Vipperman (b)
Vice President

John F. DiLorenzo, Jr.
Secretary

Armando A. Pena (d)
Treasurer

Elio Bafile
Assistant Controller and Assistant Secretary

Leonard V. Assante
Assistant Controller

William L. Scott (d)
Assistant Controller

John M. Adams, Jr. (d)
Assistant Secretary

Jeffrey D. Cross (e)
Assistant Secretary

Robert G. Griffin (f)
Assistant Secretary

Carl J. Moos (g)
Assistant Secretary

John B. Shinnock
Assistant Secretary

Bruce M. Barber
Assistant Treasurer

Christopher J. Keklak (d)
Assistant Treasurer

Gerald R. Knorr (e)
Assistant Treasurer

As of January 1, 1996 the current directors and officers of Indiana Michigan Power Company were employees of American Electric Power Service Corporation with seven exceptions: Messrs. Bafile, Blind, Boyle, Clark, Griffin, Trenary and Walters, who were employees of Indiana Michigan Power Company.

(a) Resigned January 1, 1996
(b) Elected January 1, 1996
(c) Elected April 25, 1995
(d) Elected November 1, 1995
(e) Resigned November 1, 1995
(f) Elected September 1, 1995
(g) Resigned September 1, 1995

Selected Consolidated Financial Data

	Year Ended December 31,				
	1995	1994	1993	1992	1991
			(in thousands)		
INCOME STATEMENTS DATA:					
Operating Revenues	$1,283,157	$1,251,309	$1,202,643	$1,196,755	$1,225,867
Operating Expenses	1,077,434	1,029,340	992,485	1,000,967	998,339
Operating Income	205,723	221,969	210,158	195,788	227,528
Nonoperating Income (Loss)	6,272	7,428	(234)	14,115	(3,721)
Income Before Interest Charges	211,995	229,397	209,924	209,903	223,807
Interest Charges	70,903	71,895	80,580	85,920	86,844
Net Income	141,092	157,502	129,344	123,983	136,963
Preferred Stock Dividend Requirements	11,791	11,681	14,256	15,452	15,448
Earnings Applicable to Common Stock	$ 129,301	$ 145,821	$ 115,088	$ 108,531	$ 121,515

	December 31,				
	1995	1994	1993	1992	1991
BALANCE SHEETS DATA:			(in thousands)		
Electric Utility Plant	$4,319,564	$4,269,306	$4,290,957	$4,266,480	$4,135,820
Accumulated Depreciation and Amortization	1,751,965	1,659,940	1,714,829	1,631,438	1,521,349
Net Electric Utility Plant	$2,567,599	$2,609,366	$2,576,128	$2,635,042	$2,614,471
Total Assets	$3,928,337	$3,878,035	$3,723,648	$3,608,645	$3,442,606
Common Stock and Paid-in Capital	$ 787,686	$ 790,234	$ 790,625	$ 781,818	$ 781,783
Retained Earnings	235,107	216,658	177,638	171,309	169,243
Total Common Shareholder's Equity	$1,022,793	$1,006,892	$ 968,263	$ 953,127	$ 951,026
Cumulative Preferred Stock:					
Not Subject to Mandatory Redemption	$ 52,000	$ 52,000	$ 87,000	$ 197,000	$ 197,000
Subject to Mandatory Redemption (a)	135,000	135,000	100,000	-	-
Total Cumulative Preferred Stock	$ 187,000	$ 187,000	$ 187,000	$ 197,000	$ 197,000
Long-term Debt (a)	$1,040,101	$1,069,887	$1,073,154	$1,211,623	$1,130,709
Obligations Under Capital Leases (a)	$ 142,506	$ 152,589	$ 98,753	$ 126,689	$ 102,985
Total Capitalization and Liabilities	$3,928,337	$3,878,035	$3,723,648	$3,608,645	$3,442,606

(a) Including portion due within one year.

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

Business Outlook

Since its enactment in 1992, the Energy Policy Act has fostered competition in the generation and sale of electricity in the wholesale market. The prospect for market driven rates is powering a movement, mainly among large industrial energy users, to introduce competition to the retail market as well. As a result management expects that competition will be a significant factor influencing the Company's future results of operations. Among the other factors that could impact future earnings are nuclear fuel disposal costs and nuclear decommissioning costs.

A significant expansion of competition in the generation and sale of electricity could result in an adverse effect on future results of operations from stranded costs and the write-off of regulatory assets. Stranded costs occur when a customer switches to a new supplier creating the issue of who pays for investments and commitments that are no longer needed, economical or recoverable in a competitive market. The amount of any losses the Company may experience from stranded costs depends on the extent to which direct competition is introduced to the Company's business and the market price of energy. Cost-based regulation traditionally results in the recognition of revenues and expenses in accordance with rate commission orders which can result in revenue and expense recognition in different time periods than for enterprises that are not regulated. As a result, regulatory assets have been recorded by regulated utility companies representing the deferral of costs for recovery in future periods. At December 31, 1995, the Company had $459 million of regulatory assets. In order to maintain regulatory assets, the Company's rates must be cost-based regulated. Management has reviewed the evidence currently available and concluded that the Company continues to meet the requirements to apply rate-regulated accounting standards. In the event a portion of the Company's business no longer met these requirements, regulatory assets would have to be written off for that portion of the business. Whether future results of operations are adversely affected by losses or write-offs will also depend on whether and how equitable recovery is provided for by the applicable regulators. We intend to seek appropriate recovery of any stranded costs and regulatory assets that may result from a transition to competition.

The Company, as a member of the AEP System, has the financial strength, geographic reach, location and cost structure to be an able competitor. Although no assurance can be given that the Company can maintain this position in the future, management is taking steps to prepare for the challenges that increased competition will present. In 1995 management took steps to prepare for competition by realigning the Company's operations, along with the operations of the AEP System's other operating companies, into functional operating units, expanding marketing and customer service efforts and proposing a plan for an orderly transition to retail competition. Management also proposed and filed open access transmission rates.

The realignment from separate operating company organizations to distinct fossil-fired and hydroelectric generation, nuclear generation and energy delivery operating units will facilitate the unbundling of electric services to separate competitive generation services from regulated transmission and distribution services. It also should facilitate our ability to more efficiently and effectively meet customer needs. Process improvement and cost control will be key performance objectives for our new operating units.

In October of 1995 management proposed the creation of an Independent System Operator to operate a multi-state transmission grid to facilitate equal, safe and efficient transmission. Management also proposed the eventual creation of a Regional Power Exchange that would accept offers to buy and sell power and would settle transactions based on the price at which supply and demand are balanced. Under the proposal regulators would continue to regulate delivery services and provide for the recovery of any stranded costs and regulatory assets through a usage charge.

Management has also offered access to AEP's extensive transmission grid at 142 interconnections to all parties under the same terms and conditions available to the AEP System. This should provide the Company with greater opportunities for transmission service revenues. Management has also responded to our retail customers' needs by introducing new cost-based regulated rate designs (interruptible buy-through and real time pricing).

These proposals were issued to enable the Company to participate in a meaningful way in the process of shaping the form of the future competitive playing field. Our success will depend on our ability to obtain a level playing field, improve and expand on our energy sales and services and maintain and improve on our relatively low cost structure.

Nuclear Cost

The Company's nuclear plant, the Donald C. Cook Nuclear Plant, has recently achieved a superior rating from the Institute of Nuclear Power Operations, a nuclear industry oversight group, and received improved Nuclear Regulatory Commission (NRC) performance ratings. In an effort to continue to reduce costs and enhance organizational efficiency, management announced in November that during the summer of 1996 we will consolidate our Columbus-based nuclear engineering, management and support staff with the plant staff at or near the Cook Plant in Bridgman, Michigan.

The cost to operate and maintain the two-unit Cook Plant is impacted by federal laws and NRC requirements. The Nuclear Waste Policy Act of 1982 established federal responsibility for the permanent off-site disposal of spent nuclear fuel and high-level radioactive waste. By law the Company participates in the Department of Energy's (DOE's) Spent Nuclear Fuel (SNF) disposal program which is described in Note 3 of the Notes to Consolidated Financial Statements. Since 1983 our consumers of nuclear generated electricity have paid $237 million for the future disposal, at a yet to be built DOE disposal facility, of spent nuclear fuel consumed at the Cook Plant. Under the provisions of the Nuclear Waste Policy Act, collections from customers are to provide the DOE with money to build a permanent repository for spent fuel. The federal government has not made sufficient progress toward the selection of a site and construction of a permanent repository and as long as there is a delay in establishing the permanent storage repository for spent nuclear fuel, the cost of a temporary or permanent repository will continue to increase.

The cost to decommission the Cook Plant is affected by NRC regulations and the DOE's 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. The decommissioning estimate could escalate due to uncertainty in the DOE's SNF disposal program and the length of time that SNF may need to be stored at the plant site delaying decommissioning. 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. However, future results of operations and possibly financial condition could be adversely affected if the costs of spent nuclear fuel disposal and decommissioning continue to increase and if for some reason such costs cannot be recovered.

Environmental Concerns

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, the 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 (CERCLA or Superfund legislation) addresses clean-up of hazardous substances at disposal sites and authorizes the United States Environmental Protection Agency

(Federal EPA) to administer the clean-up programs. As of year-end 1995, I&M is currently involved in litigation with respect to two sites being overseen by the Federal EPA and has been named by the Federal EPA as a "Potentially Responsible Party" (PRP) for three other sites. Information requests have been received for four additional sites which could lead to PRP designation. I&M also has received information requests with respect to two sites administered by state authorities. Liability has been resolved for a number of sites with no significant effect on results of operations. The Company's present estimates do not anticipate material cleanup costs for identified sites for which I&M has been declared a PRP. However, if for reasons not currently identified significant costs are required for cleanup, future results of operations and possibly financial condition would be adversely affected unless the costs can be recovered.

Litigation

The Company is involved in a number of legal proceedings and claims. While management is 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 the results of operations and/or financial condition.

Results of Operations

Net Income

Although revenues increased 2.5% in 1995, net income declined 10.4% to $141 million mainly due to increased operating expenses, including the unfavorable effect of a provision for severance benefits in connection with the realignment of operations and increased federal income tax expense. The increase in net income in 1994 of 21.8% was the result of a retail base rate increase in the Indiana jurisdiction, reduced interest expense due to the retirement of long-term debt, the effect of adopting Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes" (SFAS 109) in 1993 and the retirement in 1994 of a generating plant.

Operating Revenues and Energy Sales Increase

Operating revenues increased 2.5% in 1995 following a 4% increase in 1994. The changes in revenues are analyzed as follows:

	Increase (Decrease) From Previous Year			
(dollars in millions)	1995		1994	
	Amount	%	Amount	%
Retail:				
Price Variance	$ (0.7)		$ 69.8	
Volume Variance	29.9		30.5	
	29.2	3.3	100.3	12.9
Wholesale:				
Power Pool:				
Price Variance	(7.9)		(3.8)	
Volume Variance	39.4		(62.4)	
Capacity Charges	(28.3)		2.1	
	3.2		(64.1)	
Unaffiliated Utilities:				
Price Variance	(12.7)		21.1	
Volume Variance	14.0		(9.0)	
	1.3		12.1	
Total Wholesale	4.5	1.3	(52.0)	(12.8)
Other Operating Revenues	(1.9)		0.4	
Total	$ 31.8	2.5	$ 48.7	4.0

The increase in 1995 operating revenues resulted from increased energy usage by retail and unaffiliated wholesale customers. Retail energy sales increased 3% reflecting warmer summer weather in 1995 and a colder fourth quarter in 1995 than 1994 and continuing growth in the number of residential, commercial and industrial customers. While wholesale energy sales increased 34%, wholesale revenues increased only 1% in 1995. The substantial increase in wholesale energy sales was primarily due to a 69% increase in energy sales to the AEP System Power Pool (Power Pool), which are made at cost, reflecting the increased availability of lower cost nuclear generating capacity in 1995. During 1995 one nuclear generating unit was out of service for refueling while both units were refueled in 1994. Also contributing to the wholesale energy sales increase were increased sales to unaffiliated entities. Sales to the Company's municipal and cooperative customers and to unaffiliated utilities by the Power Pool which are shared by the Company increased primarily due to

the warmer summer and the colder fourth quarter weather in 1995 as compared to 1994. The increase in wholesale sales did not lead to a corresponding increase in revenues due to reduced capacity credits from the Power Pool and increasing competition in the wholesale energy market. Capacity credits are designed to allocate the cost of the AEP System's generating capacity among the members of the Power Pool based on their relative peak demands and generating reserves. An increase in the Company's peak demand during 1995 relative to the peak demand of all Power Pool members caused the decrease in capacity revenues.

In 1994 revenues rose 4% largely due to increased retail revenues partly offset by a decline in total wholesale revenues. The growth in retail revenues resulted from a $34.7 million annual base rate increase in the Indiana jurisdiction, increased decommissioning expense recoveries in the Michigan jurisdiction and a 4% increase in energy sales due to growth in the number of retail customers. The decline in 1994 wholesale revenues reflected the decrease in energy available for delivery to the Power Pool due to the scheduled refueling and maintenance outages at the Company's two 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.

Operating Expenses Increase

Total operating expenses increased 5% in 1995 or $48 million reflecting the increased operation of the Company's nuclear units and severance pay accruals. In 1994 total operating expenses rose 4% or $37 million largely due to increased accruals for nuclear decommissioning expense and employee benefits. The significant changes in operating expenses were:

	Increase (Decrease) From Previous Year			
(dollars in millions)	1995		1994	
	Amount	%	Amount	%
Fuel	$21.2	10.5	$(18.5)	(8.4)
Purchased Power	(5.8)	(4.4)	23.0	21.2
Other Operation	10.3	3.5	28.5	10.6
Federal Income Taxes	15.7	40.9	6.4	19.9

Fuel expense increased substantially in 1995 due to a 51% increase in nuclear generation reflecting the increased availability of nuclear generating capacity. During 1995 one unit was out of service for refueling while both units were out of service for refueling in 1994. Fuel expense declined in 1994 due to a significant reduction (43%) in nuclear generation reflecting the refueling outages partially offset by a 6% increase in fossil generation.

The increase in purchased power expense in 1994 reflects increased receipts from the Power Pool due to the nuclear outages and increased purchases from unaffiliated utilities for immediate resale to other unaffiliated utilities.

Other operation expense increased in 1995 primarily due to a provision for severance pay related to the functional realignment of operations and costs related to the development of a new activity based budgeting system. The 1994 increase was caused by regulatory-approved increases in nuclear decommissioning accruals, accruals for other postretirement benefits commensurate with rate recovery and expenses related to the closing of the Company's Breed Plant.

The increase in federal income taxes attributable to operations in 1995 was primarily due to changes in certain book/tax differences accounted for on a flow-through basis and the effects of favorable accrual adjustments recorded in 1994 in connection with the resolution of the audit of prior years' tax returns. Federal income taxes attributable to operations increased in 1994 due to increased pre-tax operating income.

Nonoperating Income and Financing Costs

Nonoperating income increased in 1994 reflecting a favorable tax effect from the Breed Plant closing and the unfavorable effect in 1993 of adopting SFAS 109 for nonutility assets and liabilities.

Interest charges declined in 1994 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. The full year effects from 1993 refinancings and retirements also contributed to the 1994 reduction.

Construction Spending

Gross plant and property additions were $151 million in 1995 and $212 million in 1994. Management estimates construction expenditures for the next three years to be $315 million with no major new generating plant construction planned. The funds for construction of new facilities and improvement of existing facilities can come from a combination of internally generated funds, short-term and long-term borrowings, preferred stock issuances and investments in common equity by the Company's parent, American Electric Power Co., Inc. However, all of the construction expenditures for the next three years are expected to be financed internally.

Liquidity and 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, 1995, $372 million of unused short-term lines of credit shared with other AEP System companies were available. An authorization by the Securities and Exchange Commission limits short-term borrowings to $175 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 has regulatory approval to issue up to $150 million of long-term debt. Management expects to use the proceeds of future long-term financings to retire short-term debt, refinance maturing and other long-term debt, refund cumulative preferred stock and fund construction expenditures.

The Company presently exceeds all minimum coverage requirements for issuance of mortgage bonds and preferred stock. The minimum coverage ratios are 2.0 for mortgage bonds and 1.5 for preferred stock. At December 31, 1995, the mortgage bonds and preferred stock coverage ratios were 6.25 and 2.63, respectively.

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.

New Accounting Rules

The Financial Accounting Standards Board (FASB) issued a new accounting standard, SFAS 121 "Accounting for Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of." The new standard is effective beginning with 1996 accounting periods. The initial implementation of this new standard is not expected to have a significant impact on the Company.

In 1996 the FASB issued an exposure draft "Accounting for Certain Liabilities Related to Closure or Removal of Long-Lived Assets." This document proposes that the present value of any decommissioning or other closure or removal obligation be recorded as a liability when the obligation is incurred. A corresponding asset would be recorded in the plant investment account and recovered through depreciation charges over the asset's life. A proposed transition rule would require that an entity report in income the cumulative effect of initially applying the new standard. The Company is currently studying the impact of the proposed rules and evaluating its potential impact.

INDEPENDENT AUDITORS' REPORT

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

We have audited the accompanying consolidated balance sheets of Indiana Michigan Power Company and its subsidiaries as of December 31, 1995 and 1994, and the related consolidated statements of income, retained earnings, and cash flows for each of the three years in the period ended December 31, 1995. 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, 1995 and 1994, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1995 in conformity with generally accepted accounting principles.

Deloitte & Touche LLP

DELOITTE & TOUCHE LLP
Columbus, Ohio
February 27, 1996

Consolidated Statements of Income

	Year Ended December 31,		
	1995	1994	1993
		(in thousands)	
OPERATING REVENUES	$1,283,157	$1,251,309	$1,202,643
OPERATING EXPENSES:			
Fuel	222,967	201,739	220,206
Purchased Power	125,413	131,234	108,274
Other Operation	306,967	296,625	268,144
Maintenance	141,813	139,423	142,637
Depreciation and Amortization	138,814	136,244	138,794
Amortization of Rockport Plant Unit 1 Phase-in Plan Deferrals	15,644	15,644	15,644
Taxes Other Than Federal Income Taxes	71,791	70,078	66,805
Federal Income Taxes	54,025	38,353	31,981
Total Operating Expenses	1,077,434	1,029,340	992,485
OPERATING INCOME	205,723	221,969	210,158
NONOPERATING INCOME (LOSS)	6,272	7,428	(234)
INCOME BEFORE INTEREST CHARGES	211,995	229,397	209,924
INTEREST CHARGES	70,903	71,895	80,580
NET INCOME	141,092	157,502	129,344
PREFERRED STOCK DIVIDEND REQUIREMENTS	11,791	11,681	14,256
EARNINGS APPLICABLE TO COMMON STOCK	$ 129,301	$ 145,821	$ 115,088

See Notes to Consolidated Financial Statements.

Consolidated Balance Sheets

	December 31, 1995	December 31, 1994
	(in thousands)	
ASSETS		
ELECTRIC UTILITY PLANT:		
Production	$2,507,667	$2,494,834
Transmission	867,541	849,920
Distribution	666,810	644,720
General (including nuclear fuel)	186,959	204,909
Construction Work in Progress	90,587	74,923
Total Electric Utility Plant	4,319,564	4,269,306
Accumulated Depreciation and Amortization	1,751,965	1,659,940
NET ELECTRIC UTILITY PLANT	2,567,599	2,609,366
NUCLEAR DECOMMISSIONING AND SPENT NUCLEAR FUEL DISPOSAL TRUST FUNDS	433,619	353,469
OTHER PROPERTY AND INVESTMENTS	150,994	127,424
CURRENT ASSETS:		
Cash and Cash Equivalents	13,723	9,907
Accounts Receivable:		
Customers	82,434	74,491
Affiliated Companies	21,881	24,848
Miscellaneous	11,450	20,334
Allowance for Uncollectible Accounts	(334)	(121)
Fuel - at average cost	29,093	35,802
Materials and Supplies - at average cost	72,861	59,897
Accrued Utility Revenues	43,937	40,582
Prepayments	10,191	8,414
TOTAL CURRENT ASSETS	285,236	274,154
REGULATORY ASSETS	458,525	482,107
DEFERRED CHARGES	32,364	31,515
TOTAL	$3,928,337	$3,878,035

See Notes to Consolidated Financial Statements.

	December 31, 1995	December 31, 1994
	(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	731,102	733,650
Retained Earnings	235,107	216,658
Total Common Shareholder's Equity	1,022,793	1,006,892
Cumulative Preferred Stock:		
Not Subject to Mandatory Redemption	52,000	52,000
Subject to Mandatory Redemption	135,000	135,000
Long-term Debt	1,034,048	929,887
TOTAL CAPITALIZATION	2,243,841	2,123,779
OTHER NONCURRENT LIABILITIES:		
Nuclear Decommissioning	269,392	211,963
Other	184,103	192,758
TOTAL OTHER NONCURRENT LIABILITIES	453,495	404,721
CURRENT LIABILITIES:		
Long-term Debt Due Within One Year	6,053	140,000
Short-term Debt	89,975	50,600
Accounts Payable - General	37,744	40,417
Accounts Payable - Affiliated Companies	22,962	22,720
Taxes Accrued	71,696	63,621
Interest Accrued	16,158	19,436
Obligations Under Capital Leases	31,776	39,003
Other	74,463	65,409
TOTAL CURRENT LIABILITIES	350,827	441,206
DEFERRED INCOME TAXES	612,147	634,902
DEFERRED INVESTMENT TAX CREDITS	155,202	164,206
DEFERRED GAIN ON SALE AND LEASEBACK - ROCKPORT PLANT UNIT 2	99,832	103,539
DEFERRED CREDITS	12,993	5,682
COMMITMENTS AND CONTINGENCIES (Note 3)		
TOTAL	$3,928,337	$3,878,035

Consolidated Statements of Cash Flows

	Year Ended December 31,		
	1995	1994	1993
		(in thousands)	
OPERATING ACTIVITIES:			
Net Income	$ 141,092	$ 157,502	$ 129,344
Adjustments for Noncash Items:			
Depreciation and Amortization	148,441	146,966	148,270
Amortization of Rockport Plant Unit 1 Phase-in Plan Deferrals	15,644	15,644	15,644
Amortization (Deferral) of Incremental Nuclear Refueling Outage Expenses (net)	8,684	(18,779)	33,827
Deferred Federal Income Taxes	(23,564)	(19,775)	(52,631)
Deferred Investment Tax Credits	(9,004)	(13,877)	(8,543)
Changes in Certain Current Assets and Liabilities:			
Accounts Receivable (net)	4,121	(7,200)	14,441
Fuel, Materials and Supplies	(6,255)	(3,423)	14,938
Accrued Utility Revenues	(3,355)	(5,940)	43,913
Accounts Payable	(2,431)	5,219	8,233
Taxes Accrued	8,075	9,148	38,644
Other (net)	(23,099)	(12,145)	(15,708)
Net Cash Flows From Operating Activities	258,349	253,340	370,372
INVESTING ACTIVITIES:			
Construction Expenditures	(117,785)	(118,094)	(108,867)
Long-term Receivable from Customer for Construction of Facilities	(18,733)	-	-
Proceeds from Sales of Property and Other	9,325	2,038	5,385
Net Cash Flows Used For Investing Activities	(127,193)	(116,056)	(103,482)
FINANCING ACTIVITIES:			
Capital Contributions from Parent Company	-	-	10,000
Issuance of Cumulative Preferred Stock	-	34,618	98,776
Issuance of Long-term Debt	96,819	89,221	243,426
Retirement of Cumulative Preferred Stock	-	(35,798)	(112,300)
Retirement of Long-term Debt	(141,122)	(101,833)	(392,093)
Change in Short-term Debt (net)	39,375	525	5,875
Dividends Paid on Common Stock	(110,852)	(106,608)	(108,696)
Dividends Paid on Cumulative Preferred Stock	(11,560)	(11,254)	(15,585)
Net Cash Flows Used For Financing Activities	(127,340)	(131,129)	(270,597)
Net Increase (Decrease) in Cash and Cash Equivalents	3,816	6,155	(3,707)
Cash and Cash Equivalents January 1	9,907	3,752	7,459
Cash and Cash Equivalents December 31	$ 13,723	$ 9,907	$ 3,752

See Notes to Consolidated Financial Statements.

Consolidated Statements of Retained Earnings

	Year Ended December 31,		
	1995	1994	1993
		(in thousands)	
Retained Earnings January 1	$216,658	$177,638	$171,309
Net Income	141,092	157,502	129,344
	357,750	335,140	300,653
Deductions:			
Cash Dividends Declared:			
Common Stock	110,852	106,608	108,696
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	2,360	374
6-1/4% Series	1,875	1,875	161
6.30% Series	2,205	1,978	-
6-7/8% Series	2,063	2,063	1,799
7.08% Series	2,124	2,124	2,124
7.76% Series	-	317	2,716
8.68% Series	-	-	2,517
$2.15 Series	-	-	3,001
$2.25 Series	-	-	600
Total Cash Dividends Declared	122,412	118,258	122,921
Capital Stock Expense	231	224	94
Total Deductions	122,643	118,482	123,015
Retained Earnings December 31	$235,107	$216,658	$177,638

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 to 537,000 retail customers in northern and eastern Indiana and a portion of southwestern Michigan. Wholesale electric power is supplied to neighboring utility systems. 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, which are consolidated in these financial statements, 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 subsidiary of AEP Co., Inc., I&M is subject to regulation by the Securities and Exchange Commission (SEC) under the Public Utility Holding Company Act of 1935 (1935 Act). Retail rates are regulated by the Indiana Utility Regulatory Commission (IURC) and the Michigan Public Service Commission. The Federal Energy Regulatory Commission (FERC) regulates wholesale rates.

Principles of Consolidation

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

Basis of Accounting

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

Use of Estimates

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

Utility Plant

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

The costs of labor, materials and overheads incurred to operate and maintain utility plant are included in operating expenses.

Allowance for Funds Used During Construction (AFUDC)

AFUDC is a noncash nonoperating income item that is recovered 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 amounts of AFUDC for 1995, 1994 and 1993 were not significant.

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	4.4%
Hydroelectric-Conventional	3.2%
Transmission	1.9%
Distribution	4.2%
General	3.8%

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

Cash and Cash Equivalents

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

Operating Revenues

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 and ending with the beginning of the next outage.

Income Taxes

The Company follows the liability method of accounting for income taxes as prescribed by SFAS 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 nonutility 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.

In accordance with rate-making treatment 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, debited to paid-in capital and amortized to reduce retained earnings 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

Securities held in trust funds for decommissioning nuclear facilities and for the disposal of spent nuclear fuel are recorded at market value in accordance with SFAS 115, "Accounting for Certain Investments in Debt and Equity Securities." Securities in the trust funds have been classified as available-for-sale due to their long-term purpose. Due to the rate-making process, adjustments for unrealized gains and losses are not reported in equity but result in adjustments to 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 in order to match expenses with the related revenues included in cost-based regulated rates. Regulatory assets are expected to be recovered in future periods through the rate-making process and regulatory liabilities are expected to reduce future cost recoveries. The Company has reviewed all the evidence currently available and concluded that it continues to meet the requirements to apply SFAS 71. In the event a portion of the Company's business no longer met these requirements regulatory assets and liabilities would have to be written off for that portion of the business.

Regulatory assets and liabilities are comprised of the following:

	December 31,	
	1995	1994
	(in thousands)	
Regulatory Assets:		
Amounts Due From Customers for Future Income Taxes	$309,640	$308,831
Department of Energy Decontamination and Decommissioning Assessment	48,862	51,896
Rate Phase-in Plan Deferrals	27,515	43,159
Nuclear Refueling Outage Cost Levelization	23,467	32,151
Unamortized Loss On Reacquired Debt	20,827	18,472
Other	28,214	27,598
Total Regulatory Assets	$458,525	$482,107
Regulatory Liabilities:		
Deferred Investment Tax Credits	$155,202	$164,206
Other*	1,576	350
Total Regulatory Liabilities	$156,778	$164,556

* Included in Deferred Credits on Consolidated Balance Sheets.

The Rockport Plant consists of two 1,300 megawatt (mw) coal-fired units. I&M and AEP Generating Company (AEGCo), an affiliate, each own 50% of one unit (Rockport 1) and 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. Unamortized deferred amounts under the phase-in plans were $27.5 million and $43.2 million at December 31, 1995 and 1994, respectively. Amortization was $16 million in 1995, 1994 and 1993.

3. 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 1996-1998 are estimated to be $315 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

In September 1995, the Indiana Supreme Court ruled in favor of the Company when it denied an appeal of a March 1995 opinion from the Court of Appeals of Indiana. The appeals court had upheld and affirmed a lower court's decision. The case resulted from an earlier Supreme Court of Indiana decision which overruled a lower court decision and voided an IURC order assigning a customer to the Company. The Company had received approximately $29 million in gross revenues from the customer which was not in the Company's service territory. The lower court had dismissed the case filed under a provision of Indiana law that allows a utility to seek damages equal to the gross revenues received by the Company for rendering service in the designated service territory of another utility.

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

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. In the event nuclear losses or liabilities are underinsured or exceed accumulated funds and recovery is not possible, results of operations and financial condition would be negatively affected.

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 $40.9 million annually under these policies.

Spent Nuclear Fuel Disposal

Federal law provides for government responsibility for permanent spent nuclear fuel disposal and assesses nuclear plant owners fees for spent fuel disposal. A fee of one mill per kilowatthour for fuel consumed after April 6, 1983 is being collected from customers and remitted to the U.S. Treasury. Fees and related interest of $163 million for fuel consumed prior to April 7, 1983 have been recorded as long-term debt. I&M has not paid the government the pre-April 1983 fees due to various factors including continued delays and uncertainties related to the federal disposal program. At December 31, 1995, funds collected from customers to eventually pay the pre-April 1983 fee and related earnings including accrued interest approximated the liability.

Decommissioning and Low Level Waste Accumulation Disposal

Decommissioning costs are accrued over the service life of the Cook Plant. The licenses to operate the two nuclear units expire in 2014 and 2017. After expiration of the licenses the plant is expected to be decommissioned through dismantlement. The Company's latest estimate for decommissioning and low level radioactive waste accumulation disposal costs range from $634 million to $988 million in 1993 nondiscounted dollars. The wide range is caused by variables in assumptions including the estimated length of time spent nuclear fuel must be stored at the plant subsequent to ceasing operations which depends on future developments in the federal government's spent nuclear fuel disposal program. Continued delays in the federal fuel disposal program can result in increased decommissioning costs. 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 liability equal to the decommissioning cost recovered in rates which was $30 million in 1995, $26 million in 1994 and $13 million in 1993. Decommissioning amounts recovered from customers are deposited in external trusts. Trust fund earnings increase the fund assets and the recorded liability and decrease the amount to be recovered from ratepayers. At December 31, 1995 the Company has recognized a decommissioning liability of $269 million.

4. RELATED PARTY TRANSACTIONS:

Benefits and costs of the System's generating plants are shared by members of the Power Pool. The Company is a member of the Power Pool. Under the terms of the 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. The Company is a net supplier to the pool and, therefore, receives net capacity credits from the Power Pool.

Operating revenues includes revenues for supplying energy and capacity to the Power Pool as follows:

	Year Ended December 31,		
	1995	1994	1993
		(in thousands)	
Capacity Revenues	$ 59,918	$ 88,183	$ 86,050
Energy Revenues	83,799	52,274	118,533
Total	$143,717	$140,457	$204,583

Purchased power expense includes charges of $25.4 million in 1995, $33.1 million in 1994 and $20.9 million in 1993 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 $52.6 million in 1995, $54.1 million in 1994 and $57 million in 1993.

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 $10.7 million in 1995, $14.2 million in 1994 and $5.1 million in 1993. Revenues from these transactions including a transmission fee 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 $85.2 million, $82.4 million and $78.9 million in 1995, 1994 and 1993, 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, other operation expense includes equalization credits of $46.7 million, $50.3 million and $47.4 million in 1995, 1994 and 1993, respectively.

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

	Year Ended December 31,		
	1995	1994	1993
	(in thousands)		
Affiliated Companies	$23,160	$24,001	$21,332
Unaffiliated Companies	6,992	5,021	5,757
Total	$30,152	$29,022	$27,089

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

5. BENEFIT PLANS:

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

Net pension costs for the years ended December 31, 1995, 1994 and 1993 were $2.7 million, $5 million and $4.7 million, respectively.

An employee savings plan is offered which allows participants to contribute up to 17% of their salaries into various investment alternatives, including AEP Co., Inc. common stock. An employer matching contribution, equaling one-half of the employees' contribution to the plan up to a maximum of 3% of the employees' base salary, is invested in AEP Co., Inc. common stock. The employer's annual contributions totaled $3.9 million in 1995 and 1994 and $3.5 million in 1993.

Postretirement benefits other than pensions (OPEB) are provided for retired employees under an AEP System plan. Substantially all employees are eligible for postretirement health care and life insurance if they have at least 10 service years and are age 55 or older when employment terminates.

SFAS 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions" was adopted in January 1993 for the Company's aggregate liability for 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 $13.6 million in 1995, $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 under certain conditions the increased OPEB costs which are not being currently recovered in rates. Future recovery of any deferrals and increased OPEB costs will be sought in the next base rate filings. At December 31, 1995 and 1994, $6.7 million of incremental OPEB costs were deferred.

As a result of SFAS 106, a Voluntary Employees Beneficiary Association (VEBA) trust fund for OPEB benefits was established and a corporate owned life insurance (COLI) program was implemented to lower the net OPEB costs. The insurance policies have a substantial cash surrender value which is recorded, net of equally substantial policy loans, in other property and investments. Legislation was passed by Congress which would have significantly reduced the tax benefits of a COLI program in the future. The legislation containing this provision was vetoed by the President. At this time it is uncertain if legislation repealing certain tax benefits for COLI programs will be enacted. If enacted this legislation would negatively impact the effectiveness of the COLI program as a funding and cost reduction mechanism.

The funding policy is to make VEBA trust fund contributions equal to the increase in OPEB costs resulting from the implementation of SFAS 106. These contributions include amounts collected from ratepayers and the net earnings from the COLI program. Contributions to the VEBA trust fund were $10.3 million in 1995, $6.6 million in 1994 and $1.3 million in 1993.

6. SUPPLEMENTARY INFORMATION:

	Year Ended December 31,		
	1995	1994 (in thousands)	1993
Cash was paid for:			
Interest (net of capitalized amounts)	$71,457	$68,946	$82,509
Income Taxes	88,675	85,854	68,303
Noncash Acquisitions Under Capital Leases were	32,073	92,199	15,467

In connection with the sale of western coal land and equipment the Company will receive cash payments from the buyer of $31.5 million over a six year period which has been recorded at a net present value of $26.9 million. In connection with construction of facilities to provide service to a new customer the Company will receive cash payments of $20.9 million plus accrued interest over 20 years.

7. FEDERAL INCOME TAXES:

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

	Year Ended December 31, 1995	1994 (in thousands)	1993
Charged (Credited) to Operating Expenses (net):			
Current	$ 75,686	$ 64,565	$ 93,974
Deferred	(13,732)	(18,057)	(53,685)
Deferred Investment Tax Credits	(7,929)	(8,155)	(8,308)
Total	54,025	38,353	31,981
Charged (Credited) to Nonoperating Income (net):			
Current	12,872	1,390	6,026
Deferred	(9,832)	(1,718)	1,054
Deferred Investment Tax Credits	(1,075)	(5,722)	(235)
Total	1,965	(6,050)	6,845
Total Federal Income Taxes as Reported	$ 55,990	$ 32,303	$ 38,826

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, 1995	1994 (in thousands)	1993
Net Income	$141,092	$157,502	$129,344
Federal Income Taxes	55,990	32,303	38,826
Pre-tax Book Income	$197,082	$189,805	$168,170
Federal Income Tax on Pre-tax Book Income at Statutory Rate (35%)	$68,979	$ 66,432	$58,860
Increase (Decrease) in Federal Income Tax Resulting From the Following Items:			
Depreciation	8,954	(1,033)	(747)
Adoption of SFAS 109	-	-	5,271
Corporate Owned Life Insurance	(5,187)	(4,521)	(4,697)
Nuclear Fuel Disposal Costs	(3,060)	(4,498)	(2,432)
Amortization of Deferred Investment Tax Credits (net)	(9,004)	(13,875)	(8,543)
Other	(4,692)	(10,202)	(8,886)
Total Federal Income Taxes as Reported	$55,990	$ 32,303	$38,826
Effective Federal Income Tax Rate	28.4%	17.0%	23.1%

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

	December 31, 1995	December 31, 1994
	(in thousands)	
Deferred Tax Assets	$ 221,604	$ 198,750
Deferred Tax Liabilities	(833,751)	(833,652)
Net Deferred Tax Liabilities	$(612,147)	$(634,902)
Temporary Differences in Tax Dollars:		
Property Related Temporary Differences	$(490,986)	$(498,124)
Amounts Due From Customers For Future Federal Income Taxes	(83,277)	(81,812)
Deferred State Income Taxes	(71,712)	(71,712)
Deferred Net Gain - Rockport Plant Unit 2	34,941	36,239
All Other (net)	(1,113)	(19,493)
Total Net Deferred Tax Liabilities	$(612,147)	$(634,902)

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 1991. Returns for the years 1991 through 1993 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. FAIR VALUE OF FINANCIAL INSTRUMENTS:

Nuclear Trust Funds Recorded at Market Value

The trust investments are recorded at market value in accordance with SFAS 115 and consist primarily of tax-exempt municipal bonds.

At December 31, 1995 and 1994 the fair values of trust investments were $434 million and $353 million, respectively. Accumulated gross unrealized holding gains and losses were $19.1 million and $1.0 million, respectively, at December 31, 1995. The change in market value during 1995 and 1994 was a $24.9 million net holding gain and a $27.1 million net holding loss, respectively.

The trust investments' cost basis by security type were:

	December 31, 1995	December 31, 1994
	(in thousands)	
Treasury bonds	$ 14,963	$ 997
Tax-exempt bonds	336,073	332,098
Equity securities	24,101	1,665
Cash,cash equivalents and interest accrued	40,356	25,304
Total	$415,493	$360,064

Proceeds from sales and maturities of securities of $78.2 million during 1995 resulted in $1.4 million of realized gains and $0.3 million of realized losses. Proceeds from sales and maturities of securities of $20.1 million during 1994 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, 1995, the year of maturity of trust fund investments, other than equity securities, was:

	(in thousands)
1996	$ 55,748
1997-2000	96,882
2001-2005	162,563
After 2005	76,199
Total	$391,392

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 $140 million and $117 million and for long-term debt were $1.1 billion and $1.0 billion at December 31, 1995 and 1994, respectively. The carrying amounts for preferred stock subject to mandatory redemption were $135 million at each year end and for long-term debt were $1.0 billion

and $1.1 billion at December 31, 1995 and 1994, 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.

9. 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,	
	1995	1994
	(in thousands)	
Electric Utility Plant:		
Production	$ 9,346	$ 8,371
Distribution	14,753	14,717
General:		
Nuclear Fuel (net of amortization)	69,442	89,478
Other	54,554	53,781
Total Electric Utility Plant	148,095	166,347
Accumulated Amortization	24,933	27,225
Net Electric Utility Plant	123,162	139,122
Other Property	22,361	15,842
Accumulated Amortization	3,017	2,375
Net Other Property	19,344	13,467
Net Properties under Capital Leases	$142,506	$152,589
Capital Lease Obligations:		
Noncurrent Liability	$110,730	$113,586
Liability Due Within One Year	31,776	39,003
Total Capital Lease Obligations	$142,506	$152,589

The noncurrent portion of capital lease obligations is included in other noncurrent liabilities.

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

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

	Year Ended December 31,		
	1995	1994	1993
	(in thousands)		
Operating Leases	$ 96,472	$104,519	$103,884
Amortization of Capital Leases	45,843	30,875	46,063
Interest on Capital Leases	9,987	7,643	8,873
Total Rental Costs	$152,302	$143,037	$158,820

Future minimum lease payments consisted of the following at December 31, 1995:

	Capital Leases	Non-Cancelable Operating Leases
	(in thousands)	
1996	$ 13,765	$ 98,357
1997	12,518	96,593
1998	10,620	91,454
1999	9,389	91,312
2000	8,275	91,165
Later Years	44,362	1,840,723
Total Future Minimum Lease Payments	98,929(a)	$2,309,604
Less Estimated Interest Element	25,865	
Estimated Present Value of Future Minimum Lease Payments	73,064	
Unamortized Nuclear Fuel	69,442	
Total	$142,506	

(a) Excludes nuclear fuel rentals which are paid in proportion to heat produced and carrying charges on the unamortized nuclear fuel balance. There are no minimum lease payment requirements for leased nuclear fuel.

10. CUMULATIVE PREFERRED STOCK:

At December 31, 1995, 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 1994 the Company redeemed and cancelled 350,000 shares of the 7.76% series. 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, 1995	Par Value	Shares Outstanding December 31, 1995	Amount December 31, 1995 (in thousands)	Amount December 31, 1994 (in thousands)
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
				$ 52,000	$ 52,000

B. Cumulative Preferred Stock Subject to Mandatory Redemption:

Series(a)	Par Value	Shares Outstanding December 31, 1995	Amount December 31, 1995 (in thousands)	Amount December 31, 1994 (in thousands)
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	35,000
6-7/8%(e)	100	300,000	30,000	30,000
			$135,000	$135,000

(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.

11. LONG-TERM DEBT AND LINES OF CREDIT:

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

	December 31, 1995	December 31, 1994
	(in thousands)	
First Mortgage Bonds	$ 562,017	$ 561,770
Installment Purchase Contracts	308,971	308,087
Other Long-term Debt(a)	163,060	153,977
Notes Payable to Banks	-	40,000
Sinking Fund Debentures(b)	6,053	6,053
	1,040,101	1,069,887
Less Portion Due Within One Year	6,053	140,000
Total	$1,034,048	$ 929,887

(a) Nuclear Fuel Disposal Costs including interest accrued. See Note 3.
(b) Called for redemption on March 1, 1996.

First mortgage bonds outstanding were as follows:

% Rate	Due	December 31, 1995	December 31, 1994
		(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	40,000
7.60	2002 - November 1	50,000	50,000
7.70	2002 - December 15	40,000	40,000
6.80	2003 - July 1	20,000	20,000
6.55	2003 - October 1	20,000	20,000
6.10	2003 - November 1	30,000	30,000
6.55	2004 - March 1	25,000	25,000
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	25,000
Unamortized Discount (net)		(2,983)	(3,230)
Total		$562,017	$561,770

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, 1995	December 31, 1994
		(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
6-3/4	2014 - August 1	-	50,000
(a)	2014 - August 1	50,000	50,000
7.6	2016 - March 1	40,000	40,000
6.55	2025 - June 1	50,000	-
(b)	2025 - June 1	50,000	-
City of Sullivan, Indiana:			
5.95	2009 - May 1	45,000	45,000
Unamortized Discount		(3,029)	(3,913)
		308,971	308,087
Less Portion Due Within One Year		-	100,000
Total		$308,971	$208,087

(a) The variable interest rate is determined weekly. The average weighted interest rate was 4.6% for 1995 and 3.8% for 1994.
(b) The adjustable interest rate can be a daily, weekly, commercial paper or term rate as designated by the Company. Initially, a weekly rate was selected during 1995 which ranged from 2.9% to 5% and averaged 4.0%.

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

provides for the bank to purchase any bonds not remarketed. The purchase agreement expires in 2000. Accordingly, the variable rate installment purchase contracts have been classified for repayment purposes based on the expiration dates of the standby purchase agreement and the letter of credit.

At December 31, 1995, annual long-term debt payments, excluding premium or discount, are as follows:

	Principal Amount (in thousands)
1996	$ 6,053
1997	-
1998	35,000
1999	35,000
2000	50,000
Later Years	920,060
Total	$1,046,113

Short-term debt borrowings are limited by provisions of the 1935 Act to $175 million. Lines of credit are shared with AEP System companies and at December 31, 1995 and 1994 were available in the amounts of $372 million and $558 million, respectively. Commitment fees of approximately 1/8 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:

	Balance Outstanding (in thousands)	Year-end Weighted Average Interest Rate
December 31, 1995:		
Note Payable	$52,200	6.1%
Commercial Paper	37,775	6.1
Total	$89,975	6.1
December 31, 1994:		
Commercial Paper	$50,600	6.3%

12. COMMON SHAREHOLDER'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, 1995, $5.9 million of retained earnings were restricted. Regulatory approval is required to pay dividends out of paid-in capital.

The Company received from AEP Co., Inc. a cash capital contribution of $10 million in 1993 which was credited to paid-in capital. In 1995, 1994 and 1993 net charges to paid-in capital of $2,548,000, $422,000 and $1,224,000, respectively, represented expenses of issuing and retiring cumulative preferred stock. There were no other transactions affecting the common stock and paid-in capital accounts in 1995, 1994 and 1993.

13. UNAUDITED QUARTERLY FINANCIAL INFORMATION:

Quarterly Periods Ended	Operating Revenues	Operating Income	Net Income
	(in thousands)		
1995			
March 31	$327,177	$56,311	$38,388
June 30	307,820	51,386	33,780
September 30	334,846	54,400	37,404
December 31	313,314	43,626	31,520
1994			
March 31	337,921	58,875	44,976
June 30	310,104	54,691	37,281
September 30	317,061	55,469	37,736
December 31	286,223	52,934	37,509

OPERATING STATISTICS

	1995	1994	1993	1992	1991
OPERATING REVENUES (in thousands):					
Retail:					
Residential:					
Without Electric Heating	$ 239,266	$ 227,358	$ 205,315	$ 209,682	$ 206,257
With Electric Heating	109,504	107,523	97,568	98,553	93,289
Total Residential	348,770	334,881	302,883	308,235	299,546
Commercial	256,319	247,938	220,938	228,285	216,303
Industrial	298,256	291,527	250,939	267,643	241,858
Miscellaneous	6,482	6,316	5,593	11,012	12,120
Total Retail	909,827	880,662	780,353	815,175	769,827
Wholesale (sales for resale)	357,441	352,889	404,910	369,379	436,083
Total Revenues from Energy Sales	1,267,268	1,233,551	1,185,263	1,184,554	1,205,910
Provision for Refunds of Revenues Collected in Prior Years	-	-	(755)	(4,038)	5,176
Total Net of Provision for Refunds	1,267,268	1,233,551	1,184,508	1,180,516	1,211,086
Other	15,889	17,758	18,135	16,239	14,781
Total Operating Revenues	$1,283,157	$1,251,309	$1,202,643	$1,196,755	$1,225,867
SOURCES AND SALES OF ENERGY (in millions of kilowatthours):					
Sources:					
Net Generated:					
Fossil Fuel	12,850	13,022	12,236	11,597	12,109
Nuclear Fuel	13,999	9,291	16,313	6,418	15,524
Hydroelectric	86	95	106	100	109
Total Net Generated	26,935	22,408	28,655	18,115	27,742
Purchased and Power Pool	5,871	5,757	4,879	9,342	5,237
Total Sources	32,806	28,165	33,534	27,457	32,979
Less: Losses, Company Use, Etc.	1,700	1,398	1,349	1,466	1,454
Net Sources	31,106	26,767	32,185	25,991	31,525
Sales:					
Retail:					
Residential:					
Without Electric Heating	3,390	3,210	3,178	3,001	3,166
With Electric Heating	1,768	1,727	1,706	1,633	1,625
Total Residential	5,158	4,937	4,884	4,634	4,791
Commercial	4,300	4,148	3,977	3,747	3,726
Industrial	6,582	6,453	6,025	5,685	5,382
Miscellaneous	82	82	83	194	233
Total Retail	16,122	15,620	14,969	14,260	14,132
Wholesale (sales for resale)	14,984	11,147	17,216	11,731	17,393
Total Sales	31,106	26,767	32,185	25,991	31,525

OPERATING STATISTICS (Concluded)

	1995	1994	1993	1992	1991
AVERAGE COST OF FUEL CONSUMED (in cents):					
Per Million Btu:					
Coal	126	124	130	136	141
Nuclear	43	42	36	54	48
Overall	78	85	72	103	84
Per Kilowatthour Generated:					
Coal	1.23	1.21	1.27	1.34	1.39
Nuclear	.47	.47	.40	.61	.53
Overall	.83	.90	.77	1.08	.91
RESIDENTIAL SERVICE - AVERAGES:					
Annual Kwh Use per Customer:					
With Electric Heating	18,044	17,907	17,980	17,513	17,702
Total	10,943	10,572	10,559	10,107	10,535
Annual Electric Bill:					
With Electric Heating	$1,117.55	$1,115.19	$1,028.26	$1,056.91	$1,016.16
Total	$739.99	$717.17	$654.76	$672.31	$658.76
Price per Kwh (in cents):					
With Electric Heating	6.19	6.23	5.72	6.04	5.74
Total	6.76	6.78	6.20	6.65	6.25
NUMBER OF CUSTOMERS:					
Year-End:					
Retail:					
Residential:					
Without Electric Heating	375,929	372,473	369,385	366,835	364,154
With Electric Heating	99,105	97,402	95,795	94,175	92,657
Total Residential	475,034	469,875	465,180	461,010	456,811
Commercial	55,077	53,927	53,081	52,542	51,491
Industrial	5,316	5,213	5,157	5,000	4,847
Miscellaneous	1,797	1,806	1,783	1,751	2,226
Total Retail	537,224	530,821	525,201	520,303	515,375
Wholesale (sales for resale)	62	54	56	53	53
Total Electric Customers	537,286	530,875	525,257	520,356	515,428

DIVIDENDS AND PRICE RANGES OF CUMULATIVE PREFERRED STOCK By Quarters (1995 and 1994)

	1995 - Quarters				1994 - 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	46-5/8	47-1/4	47-1/2	49-1/2	55-5/8	54-1/8	50-5/8	46-1/8
- Low	45-1/2	46-1/4	47-1/4	47-1/2	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	46-1/2	47	51	51	58-1/2	54	48	48
- Low	43	46	46	46	51	46-1/2	46-1/8	43-1/2
5.90% Series								
Dividends Paid Per Share	$1.475	$1.475	$1.475	$1.475	$1.475	$1.475	$1.475	$1.475
Market Price - $ Per Share (OTC)								
Ask (high/low)	-	-	-	-	-	-	-	-
Bid (high/low)	-	-	-	-	-	-	-	-
6-1/4% Series								
Dividends Paid Per Share	$1.5625	$1.5625	$1.5625	$1.5625	$1.5625	$1.5625	$1.5625	$1.5625
Market Price - $ Per Share (OTC)								
Ask (high/low)	-	-	-	-	-	-	-	-
Bid (high/low)	-	-	-	-	-	-	-	-
6.30% Series (a)								
Dividends Paid Per Share	$1.575	$1.575	$1.575	$1.575	$0.9275	$1.575	$1.575	$1.575
Market Price - $ Per Share (OTC)								
Ask (high/low)	-	-	-	-	-	-	-	-
Bid (high/low)	-	-	-	-	-	-	-	-
6-7/8% Series								
Dividends Paid Per Share	$1.71875	$1.71875	$1.71875	$1.71875	$1.71875	$1.71875	$1.71875	$1.71875
Market Price - $ Per Share (OTC)								
Ask (high/low)	-	-	-	-	-	-	-	-
Bid (high/low)	-	-	-	-	-	-	-	-
7.08% Series								
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	83-5/8	88-1/2	91	99-1/2	97-1/2	95	87-1/2	80
- Low	76	84	86	86	94	83	80	76

DIVIDENDS AND PRICE RANGES OF CUMULATIVE PREFERRED STOCK
By Quarters (1995 and 1994) (Concluded)

	1995 - Quarters				1994 - Quarters			
	1st	2nd	3rd	4th	1st	2nd	3rd	4th
CUMULATIVE PREFERRED STOCK								
($100 Par Value)								
7.76% Series (Redeemed)								
Dividends Paid Per Share					$0.9054			
Market Price - $ Per Share								
(NYSE) - High					101			
- Low					100			

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 February 1994

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:

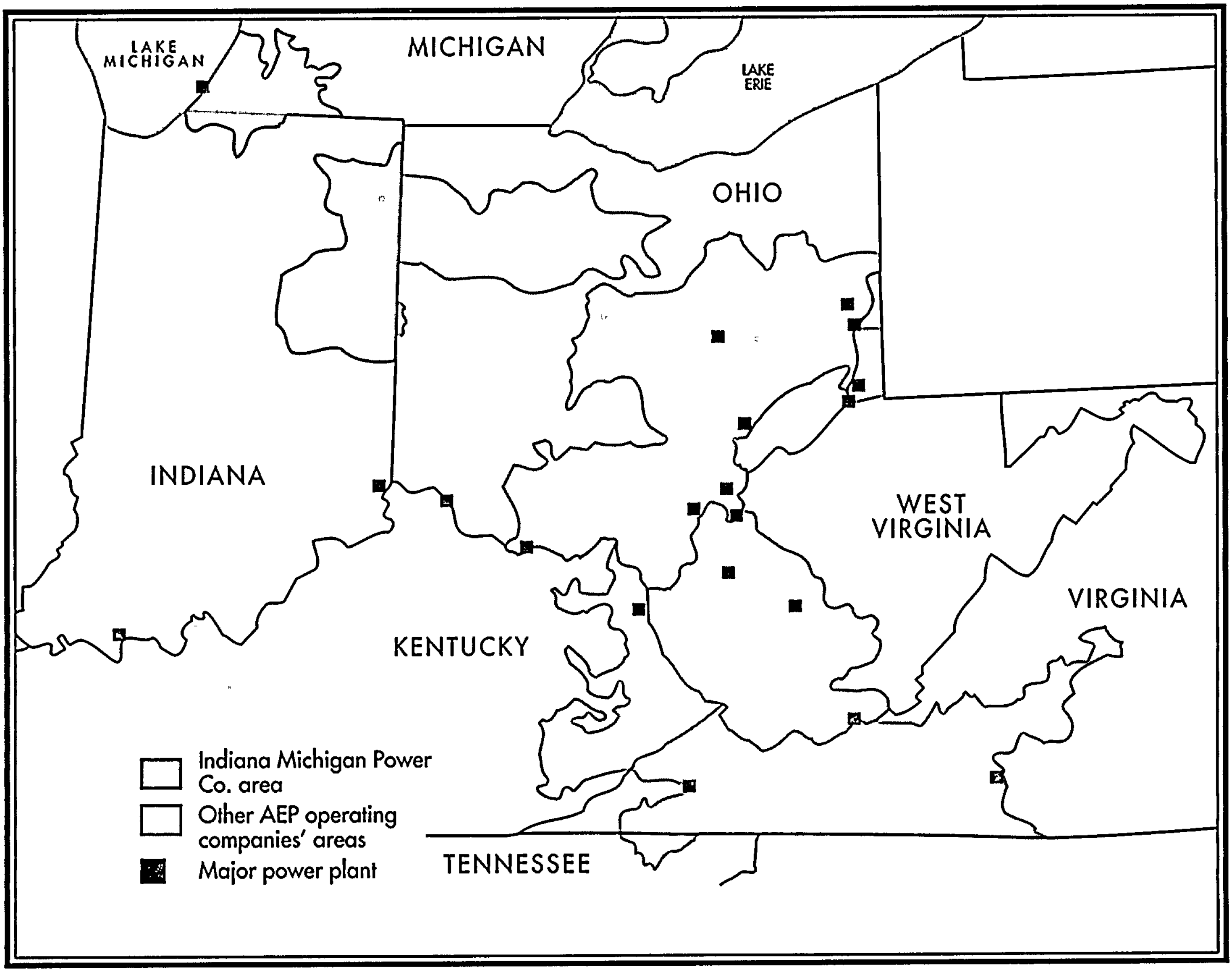
Bette Jo Rozsa
Security Owner Relations Division
American Electric Power Service Corporation
28th Floor
1 Riverside Plaza
Columbus, OH 43215-2373

FORM 10-K ANNUAL REPORT
The Annual Report (Form 10-K) to the Securities and Exchange Commission will be available in April 1996 at no cost to shareholders. 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:0909L

INDIANA MICHIGAN POWER COMPANY'S

PROJECTED CASH FLOW FOR 1996

Revision 1

Indiana Michigan Power Co.
1996 Forecasted Sources and Uses of Funds
Based on Forecasted Case 9600

$ Millions

	Projected 1996
Net Income After Taxes	150.0
Less Dividends Paid	122.3
Retained Earnings	27.7
Adjustments:	
Depreciation And Amortization	153.8
Deferred Operating Costs	9.8
Deferred Federal Income Taxes and Investment Tax Credits	(29.2)
AFUDC	(1.5)
Other	(9.2)
Total Adjustments	123.7
Internal Cash Flow	151.4
Average Quarterly Cash Flow	37.9
Average Cash Balances and Short-Term Investments	0.5
Total	38.4