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

AEP
INDIANA
MICHIGAN
POWER

April 18, 1997

AEP:NRC:0909M

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 Indiana Michigan Power Company's annual report for 1996. Attachment 2 contains a copy of Indiana Michigan Power Company's projected cash flow for 1997. These reports are submitted pursuant to 10 CFR 50.71(b) and 10 CFR 140.21(e).

Sincerely,

E E Fitzpatrick

E. E. Fitzpatrick
Vice President

vlb

Attachments

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

M004

290053

ATTACHMENT 1 TO AEP:NRC:0909M

INDIANA MICHIGAN POWER COMPANY'S
ANNUAL REPORT FOR 1996

Indiana Michigan Power Company

1996 Annual Report

AEP AMERICAN ELECTRIC POWER

INDIANA MICHIGAN POWER COMPANY
AND SUBSIDIARIES

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

CONTENTS

BACKGROUND

INDIANA MICHIGAN POWER COMPANY (the Company) is engaged in the generation, purchase, transmission and distribution of electric power. The Company serves approximately 542,000 retail customers in northern and eastern Indiana and a portion of southwestern Michigan and sells and transmits power at wholesale to other electric utilities, municipalities, electric cooperatives and non-utility entities engaged in the wholesale power market. Approximately 83% of the Company's retail sales are in Indiana and 17% in Michigan. The principal industries served are primary metals, transportation equipment, electrical and electronic machinery, fabricated metal products, rubber and miscellaneous plastic products and chemicals and allied products.

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

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

DIRECTORS

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

OFFICERS

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

William J. Lhota
President and Chief Operating Officer

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

Coulter R. Boyle, III
Vice President

Peter J. DeMaria
Vice President and Controller

Eugene E. Fitzpatrick
Vice President

Gerald P. Maloney
Vice President

James J. Markowsky
Vice President

Joseph H. Vipperman
Vice President

John F. DiLorenzo, Jr.
Secretary

Armando A. Pena
Treasurer

Elio Bafile
Assistant Controller and Assistant Secretary

Leonard V. Assante
Assistant Controller

Timothy P. Bowman (c)
Assistant Controller

William L. Scott
Assistant Controller

John M. Adams, Jr.
Assistant Secretary

Robert G. Griffin (d)
Assistant Secretary

Maurice C. McIntyre (e)
Assistant Secretary

John B. Shinnock
Assistant Secretary

Bruce M. Barber
Assistant Treasurer

Christopher J. Keklak
Assistant Treasurer

As of January 1, 1997 the current directors and officers of Indiana Michigan Power Company were employees of American Electric Power Service Corporation with eight exceptions: Messrs. Bafile, Blind, Boyle, Clark, McIntyre, Trenary, Walters and Wittkamper, who were employees of Indiana Michigan Power Company.

(a) Resigned November 20, 1996
(b) Elected November 20, 1996
(c) Elected June 1, 1996
(d) Resigned December 31, 1996
(e) Elected December 31, 1996

Selected Consolidated Financial Data

	Year Ended December 31,				
	1996	1995	1994	1993	1992
			(in thousands)		
INCOME STATEMENTS DATA:					
Operating Revenues	$1,328,493	$1,283,157	$1,251,309	$1,202,643	$1,196,755
Operating Expenses	1,108,076	1,077,434	1,029,340	992,485	1,000,967
Operating Income	220,417	205,723	221,969	210,158	195,788
Nonoperating Income (Loss)	2,729	6,272	7,428	(234)	14,115
Income Before Interest Charges	223,146	211,995	229,397	209,924	209,903
Interest Charges	65,993	70,903	71,895	80,580	85,920
Net Income	157,153	141,092	157,502	129,344	123,983
Preferred Stock Dividend Requirements	10,681	11,791	11,681	14,256	15,452
Earnings Applicable to Common Stock	$ 146,472	$ 129,301	$ 145,821	$ 115,088	$ 108,531

	December 31,				
	1996	1995	1994	1993	1992
BALANCE SHEETS DATA:			(in thousands)		
Electric Utility Plant	$4,377,669	$4,319,564	$4,269,306	$4,290,957	$4,266,480
Accumulated Depreciation and Amortization	1,861,893	1,751,965	1,659,940	1,714,829	1,631,438
Net Electric Utility Plant	$2,515,776	$2,567,599	$2,609,366	$2,576,128	$2,635,0[illegible]
Total Assets	$3,897,484	$3,928,337	$3,878,035	$3,723,648	$3,608,645
Common Stock and Paid-in Capital	$ 787,856	$ 787,686	$ 790,234	$ 790,625	$ 781,818
Retained Earnings	269,071	235,107	216,658	177,638	171,309
Total Common Shareholder's Equity	$1,056,927	$1,022,793	$1,006,892	$ 968,263	$ 953,127
Cumulative Preferred Stock:					
Not Subject to Mandatory Redemption	$ 21,977	$ 52,000	$ 52,000	$ 87,000	$ 197,000
Subject to Mandatory Redemption (a)	135,000	135,000	135,000	100,000	-
Total Cumulative Preferred Stock	$ 156,977	$ 187,000	$ 187,000	$ 187,000	$ 197,000
Long-term Debt (a)	$1,042,104	$1,040,101	$1,069,887	$1,073,154	$1,211,623
Obligations Under Capital Leases (a)	$ 130,965	$ 142,506	$ 152,589	$ 98,753	$ 126,689
Total Capitalization and Liabilities	$3,897,484	$3,928,337	$3,878,035	$3,723,648	$3,608,645

(a) Including portion due within one year.

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

Business Outlook

With the issuance of two Federal Energy Regulatory Commission (FERC) orders and the commencement of planning for retail competition at the state level, we are in a better position to identify and develop strategies for addressing the issues that face the American Electric Power (AEP) System, Indiana Michigan Power Company and our changing industry. The industry's adjustment to greater competition in generation and sales of electricity, customer choice and the ability to fully recover costs will probably be the most significant factors affecting the Company's future profitability.

Although the Company, as a member of the AEP System, has the financial strength, geographic reach, location and cost structure to be an able competitor, no assurance can be given that this position can be maintained. However, we intend to make every effort to maintain and strengthen our competitive position. We see a link between a smooth transition to a competitive marketplace and maintaining a strong financial position.

The new FERC orders facilitate increased competition in both the generation and sale of bulk power to wholesale customers. They provide, among other things, for open access to transmission facilities. AEP's support of the FERC's open access transmission rule is evidenced by our being among the first to file a comparability tariff, offering access to AEP's transmission grid at 143 interconnections to all parties under the same terms and conditions available to AEP affiliates. This has provided greater opportunities for transmission service sales.

Although customer choice proposals and discussions are under way in the states in which we operate, it is difficult to predict their result and the timing of changes, if any. We are actively involved in discussions on the state and federal level regarding whether to and how best to transition to competition in order to represent the best interests of our customers, shareholders and employees. We favor an orderly and smooth transition to a more competitive energy market because we believe that AEP will do better in the long term if it is free to compete.

If the electric energy market evolves from cost-of-service rate-making to market-based pricing, many complex issues must be resolved, including the recovery of stranded costs. While the new FERC orders provide, under certain conditions, for recovery of stranded costs at the wholesale level, the issue of stranded cost recovery remains open at the much larger state retail level.

Stranded Costs

Stranded costs occur when a customer switches to a new supplier for its electric energy needs or when a component of the business, for example generation, is no longer subject to cost-based regulation, creating the issue of who pays for plant investment, purchased power or fuel contracts both non-affiliated and affiliated, inventories, construction work in progress, nuclear decommissioning, plant removal and shutdown costs, previously deferred costs (regulatory assets) and other investments and commitments that are no longer needed, economic or recoverable in a competitive market. The amount of any stranded costs the Company may experience depends on the timing of and the extent to which direct competition is introduced to our business and the then-existing market price of energy.

Under the provisions of Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation," regulatory assets (deferred expenses) and regulatory liabilities (deferred revenues) are included in the consolidated financial statements in accordance with regulatory actions to match expenses and revenues in cost-based rates. In the event a portion of the business no longer met the requirements of SFAS 71, net regulatory assets would have to be written off for that portion of the business and assets tested for possible impairment. Whether an impairment exists would depend on how low the market price of energy is in competition relative to the cost of energy.

Among other requirements the application of SFAS 71 requires that the rates charged customers be cost based. Our generation business is still cost-based regulated and should remain so for the foreseeable future. Should enabling state legislation be enacted we believe there should be at least a three to five year transition to full competition. Although the recent FERC orders provide for competition in the firm wholesale market, that market is a relatively small part of our business and our firm wholesale sales are still under cost-of-service contracts. We believe that enabling state legislation if enacted should provide for a sufficient transition period to allow for the recovery of any generation-related

stranded costs and we are dedicating ourselves to work with regulators, customers and legislators to accomplish both an orderly transition and a reasonable and fair disposition of the stranded cost issue. However, if the Company were to no longer be cost-based regulated and recovery of stranded costs were not possible, results of operations and financial condition would be adversely affected.

Since state commissions have jurisdiction over the sale and distribution of electricity to retail customers, we believe that state legislation and regulation should shape the future competitive market for electricity while federal legislation should seek to ensure reciprocity among the states and a level playing field for all power suppliers. Presently states with higher cost power, like California, are aggressively pursuing deregulation. The states the Company operates in, however, are generally addressing the call for customer choice more cautiously.

Restructuring/Functional Unbundling

In 1996 we took some major steps to maintain and enhance the Company's competitive strength. We restructured our management and operations to allow us to comply with the new FERC orders which required separation of generation and energy sales operations from our energy transmission and delivery operations. This has achieved and should continue to achieve staffing, managerial and operating efficiencies. The generation and marketing business units are preparing for the possibility of competition in an open market for customers. Our energy delivery business expects to remain regulated and ultimately be subject to some form of incentive or performance-based ratemaking. If competition never replaces regulation we will be a more efficient and productive business as a result of our preparations which should benefit all concerned.

Marketing and customer service efforts have been enhanced with programs like the Key Accounts Program which strives to build strong partnerships with key customers in order to build customer loyalty. In 1996 we also launched a series of new television commercials to inform our customers that we will be operating under the name, American Electric Power. The commercials are intended to position AEP as more than just a supplier of electricity. We want to be the energy and energy services provider of choice; AEP: America's Energy Partner.

Cost Containment

In 1996 we continued our efforts to reduce costs in order to maintain our competitiveness. Reviews of our major processes led to decisions to consolidate the management and operations of internal service functions performed at multiple locations. Among the functions being consolidated are fossil generation plant maintenance, nuclear operations, system operations, accounting and load research. A study of the Company's procurement and supply chain operations led to cost reductions through better inventory management, just-in-time delivery and the increased use of electronic purchasing. Also in 1996 we completed the installation of an activity based management budgeting system. This tool will enable managers to better analyze work and control costs. While staff reductions and cost savings are being achieved in these and other areas, expenses for new marketing programs, customer services and modern efficient management information systems are being increased to prepare for competition. These expenditures for the future should produce further improvements and efficiencies, enabling the Company to maintain its position as a low-cost producer.

Fuel Costs

Coal is 30% of the production cost of electricity. Although our coal costs per unit of electricity (per kwh) have declined we recognize that we must continue to manage our coal costs to maintain our competitive position. As long-term coal supply contracts expire we are negotiating with non-affiliated suppliers to lower purchased coal costs. We intend to continue to prudently supplement our long-term coal supplies with spot market purchases as long as favorable spot market prices exist.

Nuclear Cost

Significant efforts have been made to enhance our competitiveness by improving the efficiency of the Company's nuclear operations. Net generation in 1996 for the Company's only nuclear plant, the two-unit Donald C. Cook Nuclear Plant, located on the shores of Lake Michigan, was 16,396 gigawatts, the highest in the plant's 20-year history. The generation record was set in part due to Unit 2's best continuous run in its history, 226 days, reached in December 1996. Refueling costs and related outage time have been reduced. We also reduced nuclear staff support costs in 1996 by relocating our Columbus-based nuclear management and support staff to Michigan to consolidate it with the plant staff.

It is difficult to reduce nuclear generation costs since major cost components are impacted by federal laws and Nuclear Regulatory Commission (NRC) regulations. The Nuclear Waste Policy Act of 1982

established federal responsibility for the permanent off-site disposal of spent nuclear fuel and high-level radioactive waste. By law we participate in the Department of Energy's (DOE's) Spent Nuclear Fuel (SNF) disposal program which is described in Note 3 of the Notes to Consolidated Financial Statements. Since 1983 our customers have paid $254 million for the disposal of spent nuclear fuel consumed at the Cook Nuclear Plant. Under the provisions of the Nuclear Waste Policy Act, collections from customers are to provide the DOE with money to build a repository for spent fuel. To date the federal government has not made sufficient progress towards a permanent repository or otherwise assuming responsibility for SNF. As long as there is a delay in the storage repository for SNF, the cost of both temporary and permanent storage will continue to increase.

The cost to decommission the Cook Nuclear Plant is also affected by NRC regulations and the DOE's SNF disposal program. Studies completed in 1994 estimate the cost to decommission the Cook Nuclear Plant and dispose of low-level nuclear waste accumulation to range from $634 million to $988 million in 1993 nondiscounted dollars. This estimate could increase due to uncertainty in the DOE's SNF disposal program and the length of time that SNF may need to be stored at the plant site delaying decommissioning. Presently we are recovering the estimated cost of decommissioning the Cook Nuclear Plant over its remaining life. However, the Company's future results of operations and possibly its financial condition could be adversely affected if the cost of spent nuclear fuel disposal and decommissioning continues to increase and cannot be recovered in regulated rates or as a stranded cost in a future competitive market.

Environmental Matters

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

By-products from the generation of electricity include materials such as ash, slag, sludge, low-level radioactive waste and spent nuclear fuel. Coal combustion by-products are typically disposed of or treated in captive disposal facilities or are beneficially utilized. In addition, our generating plants and transmission and distribution facilities have used asbestos, polychlorinated biphenyls (PCBs) and other hazardous and non-hazardous materials. The Company is currently incurring costs to safely 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) addresses clean-up of hazardous substances at disposal sites and authorized the United States Environmental Protection Agency (Federal EPA) to administer the clean-up programs. As of year-end 1996, I&M is currently involved in litigation with respect to two sites, and has been named by the Federal EPA as a "Potentially Responsible Party" (PRP) for two other sites. There are five additional sites for which the Company has received information requests which could lead to PRP designation as well as information requests for two state administered sites. I&M's 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 incurred for cleanup, future results of operations and possibly financial condition would be adversely affected unless the costs can be recovered.

Results of Operations

In 1996 net income increased $16 million or 11%. The increase is mainly attributable to increased wholesale sales, a reduction in maintenance expense and reduced financing costs. Also contributing to the 1996 increase were severance pay charges recorded in 1995 in connection with realigning operations and management and gains recorded in 1996 from emission allowance transactions. Although revenues increased 2.5% in 1995, net income declined $16 million or 10% as the result of 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.

Operating Revenues and Energy Sales Increase

Operating revenues increased 3.5% in 1996 following a 2.5% increase in 1995. The price, volume analysis of revenue variances which accounted for the improved results are:

	Increase (Decrease) From Previous Year			
(dollars in millions)	1996		1995	
	Amount	%	Amount	%
Retail:				
Price Variance	$(25.9)		$ (0.7)	
Volume Variance	32.8		29.9	
	6.9	0.8	29.2	3.3
Wholesale:				
Price Variance	(55.6)		(116.9)	
Volume Variance	89.6		121.4	
	34.0	9.5	4.5	1.3
Other Operating Revenues	4.4		(1.9)	
Total	$ 45.3	3.5	$ 31.8	2.5

Operating revenues increased in 1996 primarily as a result of increased wholesale sales attributable to increased internal generation being supplied to the AEP System Power Pool (Power Pool) and unaffiliated utilities. The Company's share of Power Pool allocated sales increased 40% due to increased transactions with other utilities and power marketers. During 1996 the Company provided a new product, coal conversion services, to power marketers and unaffiliated utilities resulting in 1.2 billion kilowatthours of electricity being generated under a new FERC-approved interruptible tariff. Under this tariff the Company converts the coal of a wholesale customer to electricity for a fee.

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 and a colder fourth quarter in 1995 than in 1994 and continued growth in the number of retail customers. While wholesale energy sales increased 34%, wholesale revenues increased by only 1% in 1995. The substantial increase in wholesale energy sales was primarily due to a 69% increase in energy sales to the Power Pool reflecting the increased availability of the Company's 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. Sales to the Company's municipal and cooperative customers and to unaffiliated utilities by the Power Pool increased primarily due to weather related factors in 1995 versus 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, which 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, were lower reflecting the effect of an increase in the Company's peak demand during 1995.

Operating Expenses Increase

Total operating expenses increased 2.8% in 1996 or $30.6 million mainly due to the increased operation of the Company's nuclear units, increased Power Pool wholesale transactions, and higher income taxes partially offset by significant reductions in maintenance expense. In 1995, total operating expenses rose 4.7% or $48.1 million reflecting the increased operation of the Company's nuclear units and severance pay accruals. The significant changes in operating expenses were:

	Increase (Decrease) From Previous Year			
(dollars in millions)	1996		1995	
	Amount	%	Amount	%
Fuel	$ 13.3	6.0	$ 21.2	10.5
Purchased Power	13.3	10.6	(5.8)	(4.4)
Other Operation	3.5	1.2	10.3	3.5
Maintenance	(26.5)	(18.7)	2.4	1.7
Federal Income Taxes	23.5	43.5	15.7	40.9

Fuel expense increased in 1996 due to a 17% increase in nuclear generation made possible by the shorter refueling outage in 1996 versus an extended refueling and maintenance outage in 1995. This increase was partially offset by a lower average price per ton of coal consumed from a favorable settlement of a coal transportation dispute. Fuel expense increased substantially in 1995 due to a 51% increase in nuclear generation reflecting the increased availability from having only one refueling outage in 1995 versus two in 1994.

The 1996 rise in purchased power expense was mainly due to additional power purchases under an agreement with the Ohio Valley Electric Corporation, an affiliated company which is not a member of the Power Pool, and increased purchases from the Power Pool to support the Company's allocated share of higher Power Pool wholesale transactions with nonaffiliated utilities. The 1995 reduction in purchased power expense can be attributed to increased availability of the Company's nuclear generation.

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.

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

The increase in 1996 federal income taxes resulted from an increase in pre-tax operating income and changes in certain book/tax differences accounted for on a flow-through basis for rate-making purposes. Federal income taxes increased in 1995 primarily due to changes in certain book/tax timing 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.

Financing Costs

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

Construction Spending

Gross plant and property additions were $144 million in 1996 and $151 million in 1995. Management estimates construction expenditures for the next three years to be $340 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 Company, Inc. (AEP Co., Inc.) However, all of the construction expenditures for the next three years are expected to be financed with internally generated funds.

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, 1996, $409 million of unused short-term lines of credit shared with other AEP System companies were available. Short-term debt borrowings are limited by provisions of the Public Utility Holding Company Act of 1935 to $175 million. 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's earnings coverage presently exceeds all minimum coverage requirements for the issuance of mortgage bonds and preferred stock. The minimum coverage ratios are 2.0 for mortgage bonds and 1.5 for preferred stock. At December 31, 1996, the mortgage bonds and preferred stock coverage ratios were 6.66 and 3.07, respectively.

In January 1997 a tender offer was announced for all of the Company's preferred stock in conjunction with a special meeting scheduled to be held on February 28, 1997. The special meeting's purpose is to consider amendments to the Company's articles of incorporation to remove certain capitalization ratio requirements. These restrictions limit the Company's financial flexibility and could place it at a competitive disadvantage in the future. The amount paid to redeem the preferred stock that is tendered could total as much as $154 million. A combination of short-term debt and unsecured long-term debt is expected to be used to pay for the preferred stock tendered.

Litigation

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

Effects of Inflation

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

Corporate Owned Life Insurance

In connection with the audit of the AEP System's 1991, 1992 and 1993 consolidated federal income tax returns the Internal Revenue Service (IRS) agents sought a ruling from the IRS National Office that certain interest deductions relating to a corporate owned life insurance (COLI) program should not be allowed. The Company established the COLI program in 1990 as a part of its strategy to fund and reduce the cost of medical benefits for retired employees.

AEP filed a brief with the IRS National Office refuting the agents' position. Although no adjustments have been proposed, a disallowance of the COLI interest deductions through December 31, 1996 would reduce earnings by approximately $51 million (including interest). Management believes it will ultimately prevail on this issue and will vigorously contest any disallowance that may be assessed.

In 1996 Congress enacted legislation that prospectively phases out the tax benefits for COLI interest deductions over a three year period beginning in 1996. As a result the Company intends to restructure its COLI program. The restructuring of the COLI program is not expected to have a material impact on results of operations.

New Accounting Rule

In 1996 the Financial Accounting Standards Board (FASB) issued an exposure draft "Accounting for Certain Liabilities Related to Closure or Removal of Long-Lived Assets." The Company generally records such liabilities over the life of its plant commensurate with rate recovery. The exposure draft proposes that the present value of decommissioning and certain other closure or removal obligations 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. However, as a cost-based rate-regulated entity, the Company would expect to record a corresponding regulatory asset for the cumulative effect of initially applying the new standard. The FASB is reconsidering several aspects of the exposure draft. It is unclear at this time what, if any, changes the FASB will make to the proposal. Until it becomes apparent what the FASB will decide and how certain questions raised by the exposure draft are resolved the Company cannot determine its ultimate 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, 1996 and 1995, and the related consolidated statements of income, retained earnings, and cash flows for each of the three years in the period ended December 31, 1996. 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, 1996 and 1995, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1996 in conformity with generally accepted accounting principles.

Deloitte & Touche LLP

DELOITTE & TOUCHE LLP
Columbus, Ohio
February 25, 1997

Consolidated Statements of Income

	Year Ended December 31,		
	1996	1995 (in thousands)	1994
OPERATING REVENUES	$1,328,493	$1,283,157	$1,251,309
OPERATING EXPENSES:			
Fuel	236,237	222,967	201,739
Purchased Power	138,687	125,413	131,234
Other Operation	310,513	306,967	296,625
Maintenance	115,300	141,813	139,423
Depreciation and Amortization	140,437	138,814	136,244
Amortization of Rockport Plant Unit 1 Phase-in Plan Deferrals	15,644	15,644	15,644
Taxes Other Than Federal Income Taxes	73,729	71,791	70,078
Federal Income Taxes	77,529	54,025	38,353
Total Operating Expenses	1,108,076	1,077,434	1,029,340
OPERATING INCOME	220,417	205,723	221,969
NONOPERATING INCOME	2,729	6,272	7,428
INCOME BEFORE INTEREST CHARGES	223,146	211,995	229,397
INTEREST CHARGES	65,993	70,903	71,895
NET INCOME	157,153	141,092	157,502
PREFERRED STOCK DIVIDEND REQUIREMENTS	10,681	11,791	11,681
EARNINGS APPLICABLE TO COMMON STOCK	$ 146,472	$ 129,301	$ 145,821

See Notes to Consolidated Financial Statements.

Consolidated Statements of Cash Flows

	Year Ended December 31,		
	1996	1995	1994
		(in thousands)	
OPERATING ACTIVITIES:			
Net Income	$ 157,153	$ 141,092	$ 157,502
Adjustments for Noncash Items:			
Depreciation and Amortization	148,123	148,441	146,966
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)	7,662	8,684	(18,779)
Deferred Federal Income Taxes	(24,687)	(23,564)	(19,775)
Deferred Investment Tax Credits	(8,729)	(9,004)	(13,877)
Changes in Certain Current Assets and Liabilities:			
Accounts Receivable (net)	(10,235)	4,121	(7,200)
Fuel, Materials and Supplies	903	(6,255)	(3,423)
Accrued Utility Revenues	5,642	(3,355)	(5,940)
Accounts Payable	1,186	(2,431)	5,219
Taxes Accrued	(6,296)	8,075	9,148
Other (net)	7,975	(23,099)	(12,145)
Net Cash Flows From Operating Activities	294,341	258,349	253,340
INVESTING ACTIVITIES:			
Construction Expenditures	(95,046)	(117,785)	(118,094)
Long-term Receivable from Customer for Construction of Facilities	62	(18,733)	-
Proceeds from Sales of Property and Other	2,714	9,325	2,038
Net Cash Flows Used For Investing Activities	(92,270)	(127,193)	(116,056)
FINANCING ACTIVITIES:			
Issuance of Cumulative Preferred Stock	-	-	34,618
Issuance of Long-term Debt	38,579	96,819	89,221
Retirement of Cumulative Preferred Stock	(30,568)	-	(35,798)
Retirement of Long-term Debt	(46,091)	(141,122)	(101,833)
Change in Short-term Debt (net)	(46,475)	39,375	525
Dividends Paid on Common Stock	(112,508)	(110,852)	(106,608)
Dividends Paid on Cumulative Preferred Stock	(10,498)	(11,560)	(11,254)
Net Cash Flows Used For Financing Activities	(207,561)	(127,340)	(131,129)
Net Increase (Decrease) in Cash and Cash Equivalents	(5,490)	3,816	6,155
Cash and Cash Equivalents January 1	13,723	9,907	3,752
Cash and Cash Equivalents December 31	$ 8,233	$ 13,723	$ 9,907

See Notes to Consolidated Financial Statements.

Consolidated Balance Sheets

	December 31, 1996	December 31, 1995
	(in thousands)	
ASSETS		
ELECTRIC UTILITY PLANT:		
Production	$2,525,969	$2,507,667
Transmission	881,407	867,541
Distribution	696,069	666,810
General (including nuclear fuel)	189,619	186,959
Construction Work in Progress	84,605	90,587
Total Electric Utility Plant	4,377,669	4,319,564
Accumulated Depreciation and Amortization	1,861,893	1,751,965
NET ELECTRIC UTILITY PLANT	2,515,776	2,567,599
NUCLEAR DECOMMISSIONING AND SPENT NUCLEAR FUEL DISPOSAL TRUST FUNDS	490,778	433,619
OTHER PROPERTY AND INVESTMENTS	154,265	150,994
CURRENT ASSETS:		
Cash and Cash Equivalents	8,233	13,723
Accounts Receivable:		
Customers	90,656	82,434
Affiliated Companies	13,727	21,881
Miscellaneous	21,439	11,450
Allowance for Uncollectible Accounts	(156)	(334)
Fuel - at average cost	23,977	29,093
Materials and Supplies - at average cost	77,074	72,861
Accrued Utility Revenues	38,295	43,937
Prepayments	10,271	10,191
TOTAL CURRENT ASSETS	283,516	285,236
REGULATORY ASSETS	421,692	458,525
DEFERRED CHARGES	31,457	32,364
TOTAL	$3,897,484	$3,928,337

See Notes to Consolidated Financial Statements.

	December 31, 1996	December 31, 1995
	(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	731,272	731,102
Retained Earnings	269,071	235,107
Total Common Shareholder's Equity	1,056,927	1,022,793
Cumulative Preferred Stock:		
Not Subject to Mandatory Redemption	21,977	52,000
Subject to Mandatory Redemption	135,000	135,000
Long-term Debt	1,042,104	1,034,048
TOTAL CAPITALIZATION	2,256,008	2,243,841
OTHER NONCURRENT LIABILITIES:		
Nuclear Decommissioning	313,845	269,392
Other	174,903	184,103
TOTAL OTHER NONCURRENT LIABILITIES	488,748	453,495
CURRENT LIABILITIES:		
Long-term Debt Due Within One Year	-	6,053
Short-term Debt	43,500	89,975
Accounts Payable - General	31,015	37,744
Accounts Payable - Affiliated Companies	30,877	22,962
Taxes Accrued	65,400	71,696
Interest Accrued	15,281	16,158
Obligations Under Capital Leases	29,740	31,776
Other	66,436	74,463
TOTAL CURRENT LIABILITIES	282,249	350,827
DEFERRED INCOME TAXES	594,879	612,147
DEFERRED INVESTMENT TAX CREDITS	146,473	155,202
DEFERRED GAIN ON SALE AND LEASEBACK - ROCKPORT PLANT UNIT 2	96,125	99,832
DEFERRED CREDITS	33,002	12,993
COMMITMENTS AND CONTINGENCIES (Note 3)		
TOTAL	$3,897,484	$3,928,337

Consolidated Statements of Retained Earnings

	Year Ended December 31,		
	1996	1995	1994
		(in thousands)	
Retained Earnings January 1	$235,107	$216,658	$177,638
Net Income	157,153	141,092	157,502
	392,260	357,750	335,140
Deductions:			
Cash Dividends Declared:			
Common Stock	112,508	110,852	106,608
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	2,360
6-1/4% Series	1,875	1,875	1,875
6.30% Series	2,205	2,205	1,978
6-7/8% Series	2,063	2,063	2,063
7.08% Series	531	2,124	2,124
7.76% Series	-	-	317
Total Cash Dividends Declared	122,475	122,412	118,258
Capital Stock Expense	714	231	224
Total Deductions	123,189	122,643	118,48[illegible]
Retained Earnings December 31	$269,071	$235,107	$216,658

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 542,000 retail customers in its service territory of northern and eastern Indiana and a portion of southwestern Michigan. Wholesale electric power is supplied to neighboring utility systems, power marketers and the American Electric Power (AEP) System Power Pool (Power Pool). As a member of the 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 (MPSC). The Federal Energy Regulatory Commission (FERC) regulates wholesale rates.

Principles of Consolidation

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

Basis of Accounting

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

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 1996, 1995 and 1994 were not significant.

Depreciation and Amortization

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

Functional Class of Property	Composite Depreciation 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, based on a twenty quarter rolling average, the fuel clause mechanism provides for the refunding of the excess earnings to ratepayers. Wholesale jurisdictional fuel cost changes are expensed and billed as incurred.

Levelization of Nuclear Refueling Outage Costs

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

Income Taxes

The Company follows the liability method of accounting for income taxes as prescribed by SFAS 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. Deferred investment tax credits, which represent a regulatory liability, are being amortized over the life of the related plant investment commensurate with recovery in rates. The Company's policy with regard to investment tax credits for nonutility property is to practice the flow-through method of accounting.

Debt and Preferred Stock

Gains and losses on 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 is credited to paid-in capital and amortized to retained earnings.

Nuclear Decommissioning and Spent Nuclear Fuel Disposal Trust Funds

Securities held in trust funds for decommissioning nuclear facilities and for the disposal of spent nuclear fuel are recorded at market value in accordance with SFAS 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.

2. EFFECTS OF REGULATION AND PHASE-IN PLANS:

In accordance with SFAS 71 the consolidated financial statements include assets (deferred expenses) and liabilities (deferred income) 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 the regulatory liabilities are expected to reduce future cost recoveries. Among other things , application of SFAS 71 requires that the Company's rates be cost-based regulated. The Company has reviewed all the evidence currently available and concluded that it continues to meet the requirements to apply SFAS 71. In the event a portion of the Company's business were to no longer meet those requirements net regulatory assets would have to be written off for that portion of the business and assets would have to be tested for possible impairment.

Regulatory assets and liabilities are comprised of the following:

	December 31,	
	1996	1995
	(in thousands)	
Regulatory Assets:		
Amounts Due From Customers for Future Income Taxes	$317,059	$309,640
Department of Energy Decontamination and Decommissioning Assessment	45,994	48,862
Rate Phase-in Plan Deferrals	11,871	27,515
Nuclear Refueling Outage Cost Levelization	15,805	23,467
Unamortized Loss On Reacquired Debt	19,388	20,827
Other	11,575	28,214
Total Regulatory Assets	$421,692	$458,525
Regulatory Liabilities:		
Deferred Investment Tax Credits	$146,473	$155,202
Other*	16	1,576
Total Regulatory Liabilities	$146,489	$156,778

* Included in Deferred Credits on Consolidated Balance Sheets.

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

Rate phase-in plans in the Company's Indiana and FERC jurisdictions 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 $11.9 million and $27.5 million at December 31, 1996 and 1995, respectively. Amortization was $15.6 million in 1996, 1995 and 1994.

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 1997-1999 are estimated to be $340 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

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

Nuclear Plant

I&M owns and operates the two-unit 2,110 mw Donald C. Cook Nuclear Plant under licenses granted by the Nuclear Regulatory Commission. The operation of a nuclear facility involves special risks, potential liabilities, and specific regulatory and safety requirements. Should a nuclear incident occur at any nuclear power plant facility in the United States, the resultant liability could be substantial. By agreement I&M is partially liable together with all other electric utility companies that own nuclear generating units for a nuclear power plant incident. In the event nuclear losses or liabilities are underinsured or exceed accumulated funds and recovery is not possible, results of operations 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 $35.8 million annually under these policies.

Spent Nuclear Fuel Disposal

Federal law provides for government responsibility for permanent spent nuclear fuel disposal and assesses nuclear plant owners fees for spent fuel disposal. A fee of one mill per kilowatthour for fuel consumed after April 6, 1983 is being collected from customers and remitted to the U.S. Treasury. Fees and related interest of $172 million for fuel consumed prior to April 7, 1983 have been recorded as long-term debt. I&M has not paid the government the pre-April 1983 fees due to continued delays and uncertainties related to the federal disposal program. At December 31, 1996, funds collected from customers towards the pre-April 1983 fee and related earnings thereon approximate the liability.

Decommissioning and Low Level Waste Accumulation Disposal

Decommissioning costs are accrued over the service life of the Cook Plant. The licenses to operate the two nuclear units expire in 2014 and 2017. After expiration of the licenses the plant is expected to be decommissioned through dismantlement. 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. This in turn depends on future developments in the federal government's spent nuclear fuel disposal program. Continued delays in the federal fuel disposal program can result in increased decommissioning costs. The Company is recovering estimated decommissioning costs in its three rate-making jurisdictions based on at least the lower end of the range in the most recent decommissioning study at the time of the last rate proceeding. The Company records decommissioning costs in other operation expense and records a noncurrent liability equal to the decommissioning cost recovered in rates; such amount was $27 million in 1996, $30 million in 1995 including $4 million of special deposits and $26 million in 1994. Decommissioning costs recovered from customers are deposited in external trusts. Trust fund earnings increase the fund assets and the recorded liability and decrease the amount needed to be recovered from ratepayers. At December 31, 1996 the Company has recognized a decommissioning liability of $314 million which is included in other noncurrent liabilities.

4. RELATED PARTY TRANSACTIONS:

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

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

	Year Ended December 31,		
	1996	1995	1994
	(in thousands)		
Capacity Revenues	$ 57,594	$ 59,918	$ 88,183
Energy Revenues	98,162	83,799	52,274
Total	$155,756	$143,717	$140,457

Purchased power expense includes charges of $34.5 million in 1996, $25.4 million in 1995 and $33.1 million in 1994 for energy received from the Power Pool.

Power Pool members share in wholesale sales to unaffiliated entities made by the Power Pool. The Company's share of the wholesale power pool sales included in operating revenues were $73.4 million in 1996, $52.6 million in 1995 and $54.1 million in 1994.

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 $8.1 million in 1996, $10.7 million in 1995 and $14.2 million in 1994. 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 $85.4 million, $85.2 million and $82.4 million in 1996, 1995 and 1994, respectively.

The cost of power purchased from Ohio Valley Electric Corporation, an affiliated but non-associated Company that is not a member of the Power Pool, was included in purchased power expense in the amounts of $10.7 million, $4.0 million and $.9 million in 1996, 1995 and 1994, respectively.

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

AEP System companies participate in a transmission equalization agreement. This agreement combines certain AEP System companies' investments in transmission facilities and shares the costs of ownership in proportion to the AEP System companies' respective peak demands. Pursuant to the terms of the agreement, other operation expense includes equalization credits of $46.3 million, $46.7 million and $50.3 million in 1996, 1995 and 1994, respectively.

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

	Year Ended December 31,		
	1996	1995	1994
	(in thousands)		
Affiliated Companies	$22,740	$23,160	$24,001
Unaffiliated Companies	6,776	6,992	5,021
Total	$29,516	$30,152	$29,022

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, 1996, 1995 and 1994 were $4.1 million, $2.7 million and $5 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 $3.7 million in 1996 and $3.9 million in 1995 and 1994.

Postretirement benefits other than pensions (OPEB) are provided for retired employees under an AEP System plan. Substantially all employees are eligible for postretirement health care and life insurance if they retire from active service after reaching age 55 and have at least 10 service years. The funding policy for OPEB cost is to make contributions to an external Voluntary Employees Beneficiary Association trust fund equal to the incremental OPEB costs (i.e., the amount that the total postretirement benefits cost under SFAS 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions," exceeds the pay-as-you-go amount). Contributions were $8.4 million in 1996, $10.3 million in 1995, and $6.6 million in 1994. OPEB costs are determined by the application of AEP System actuarial assumptions to each company's employee complement. The Company's annual accrued costs for 1996, 1995 and 1994 required by SFAS 106 for employees and retirees were $12.8 million, $13.6 million and $13.2 million, respectively.

6. SUPPLEMENTARY INFORMATION:

	Year Ended December 31,		
	1996	1995	1994
	(in thousands)		
Cash was paid for:			
Interest (net of capitalized amounts)	$ 64,117	$71,457	$68,946
Income Taxes	125,707	88,675	85,854
Noncash Acquisitions Under Capital Leases were	48,305	32,073	92,199

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

7. FEDERAL INCOME TAXES:

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

	Year Ended December 31,		
	1996	1995	1994
		(in thousands)	
Charged (Credited) to Operating Expenses (net):			
Current	$110,133	$ 75,686	$ 64,565
Deferred	(24,730)	(13,732)	(18,057)
Deferred Investment Tax Credits	(7,874)	(7,929)	(8,155)
Total	77,529	54,025	38,353
Charged (Credited) to Nonoperating Income (net):			
Current	182	12,872	1,390
Deferred	43	(9,832)	(1,718)
Deferred Investment Tax Credits	(855)	(1,075)	(5,722)
Total	(630)	1,965	(6,050)
Total Federal Income Taxes as Reported	$ 76,899	$ 55,990	$ 32,303

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,		
	1996	1995	1994
		(in thousands)	
Net Income	$157,153	$141,092	$157,502
Federal Income Taxes	76,899	55,990	32,303
Pre-tax Book Income	$234,052	$197,082	$189,805
Federal Income Tax on Pre-tax Book Income at Statutory Rate (35%)	$81,918	$68,979	$ 66,432
Increase (Decrease) in Federal Income Tax Resulting From the Following Items:			
Depreciation	13,880	8,954	(1,033)
Corporate Owned Life Insurance	(2,178)	(5,187)	(4,521)
Nuclear Fuel Disposal Costs	(3,096)	(3,060)	(4,498)
Investment Tax Credits (net)	(8,729)	(9,004)	(13,875)
Other	(4,896)	(4,692)	(10,202)
Total Federal Income Taxes as Reported	$76,899	$55,990	$ 32,303
Effective Federal Income Tax Rate	32.9%	28.4%	17.0%

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

	December 31,	
	1996	1995
	(in thousands)	
Deferred Tax Assets	$ 241,842	$ 221,604
Deferred Tax Liabilities	(836,721)	(833,751)
Net Deferred Tax Liabilities	$(594,879)	$(612,147)
Property Related Temporary Differences	$(480,818)	$(490,986)
Amounts Due From Customers For Future Federal Income Taxes	(79,658)	(83,277)
Deferred State Income Taxes	(89,471)	(71,712)
Deferred Net Gain - Rockport Plant Unit 2	33,644	34,941
All Other (net)	21,424	(1,113)
Total Net Deferred Tax Liabilities	$(594,879)	$(612,147)

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 AEP System companies is in accordance with SEC rules under the 1935 Act. These rules permit the allocation of the benefit of current tax losses to the AEP System companies giving rise to them in determining their current tax expense. The tax loss of the parent company, AEP Co., Inc., is allocated to its subsidiaries with taxable income. With the exception of the loss of the 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. During the audit the IRS agents requested a ruling from their National Office that certain interest deductions relating to corporate owned life insurance (COLI) claimed by the Company for 1991 through 1993 should not be allowed. The COLI program was established in 1990 as part of the Company's strategy to fund and reduce the cost of medical benefits for retired employees. AEP filed a brief with the IRS National Office refuting the agents' position. Although no adjustments have been proposed, a disallowance of the COLI interest deductions through December 31, 1996 would reduce earnings by approximately $51 million (including interest). Management believes it will ultimately prevail on this issue and will vigorously contest any adjustments that may be assessed. Accordingly, no provision for this amount has been recorded. 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 of long-term tax-exempt municipal bonds and other securities.

At December 31, 1996 and 1995 the fair values of trust investments were $491 million and $434 million, respectively. Accumulated gross unrealized holding gains were $22 million and $19.1 million and accumulated gross unrealized holding losses were $1.2 million and $1 million at December 31, 1996 and 1995, respectively. The change in market value in 1996 was a net unrealized holding gain of $2.6 million, in 1995 a net unrealized holding gain of $24.9 million and in 1994 a net unrealized holding loss of $27.1 million.

The trust investments' cost basis by security type were:

	December 31, 1996	December 31, 1995
	(in thousands)	
Tax-Exempt Bonds	$340,290	$336,073
Equity Securities	54,389	24,101
Treasury bonds	26,958	12,992
Corporate Bonds	7,977	1,971
Cash, Cash Equivalents and Interest Accrued	40,430	40,356
Total	$470,044	$415,493

Proceeds from sales and maturities of securities of $115.3 million during 1996 resulted in $2.6 million of realized gains and $2.1 million of realized losses. Proceeds from sales and maturities of securities of $78.2 million during 1995 resulted in $1.4 million of realized gains and $0.3 million of realized losses. During 1994 proceeds from sales and maturities of securities of $20.1 million 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, 1996, the year of maturity of trust fund investments, other than equity securities, was:

	(in thousands)
1997	$ 56,452
1998-2001	120,327
2002-2006	163,250
After 2006	75,626
Total	$415,655

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 $137 million and $140 million at December 31, 1996 and 1995, respectively, and for long-term debt were $1.1 billion at each year end. The carrying amounts for preferred stock subject to mandatory redemption were $135 million at each year end and for long-term debt were $1.0 billion at December 31, 1996 and 1995. 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 estimated fair value.

9. LEASES:

Leases of property, plant and equipment are for periods of up to 35 years and require payments of related property taxes, maintenance and operating costs. The majority of the leases have purchase or renewal options and will be renewed or replaced by other leases.

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

	Year Ended December 31,		
	1996	1995	1994
	(in thousands)		
Operating Leases	$ 96,096	$ 96,472	$104,519
Amortization of Capital Leases	55,789	45,843	30,875
Interest on Capital Leases	10,624	9,987	7,643
Total Rental Costs	$162,509	$152,302	$143,037

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

	December 31,	
	1996	1995
	(in thousands)	
Electric Utility Plant:		
Production	$ 7,410	$ 9,346
Distribution	14,699	14,753
General:		
Nuclear Fuel (net of amortization)	59,681	69,442
Other	60,949	54,554
Total Electric Utility Plant	142,739	148,095
Accumulated Amortization	28,598	24,933
Net Electric Utility Plant	114,141	123,162
Other Property	19,035	22,361
Accumulated Amortization	2,211	3,017
Net Other Property	16,824	19,344
Net Properties under Capital Leases	$130,965	$142,506
Capital Lease Obligations:*		
Noncurrent Liability	$101,225	$110,730
Liability Due Within One Year	29,740	31,776
Total Capital Lease Obligations	$130,965	$142,506

* Represents the present value of future minimum lease payments.

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

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

Future minimum lease payments consisted of the following at December 31, 1996:

	Capital Leases	Non-Cancelable Operating Leases
	(in thousands)	
1997	$ 14,685	$ 96,294
1998	12,474	91,397
1999	11,027	91,551
2000	9,848	91,403
2001	8,281	90,802
Later Years	36,371	1,749,187
Total Future Minimum Lease Payments	92,686(a)	$2,210,634
Less Estimated Interest Element	21,402	
Estimated Present Value of Future Minimum Lease Payments	71,284	
Unamortized Nuclear Fuel	59,681	
Total	$130,965	

(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, 1996, 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.

In January 1997 a tender offer for all series of preferred stock was announced. In conjunction with the tender offer a special shareholders' meeting was scheduled to be held on February 28, 1997 for the purpose of considering amendments to the Company's articles of incorporation to remove certain capitalization ratio requirements.

A. Cumulative Preferred Stock Not Subject to Mandatory Redemption:

Series	Call Price December 31, 1996	Par Value	Number of Shares Redeemed Year Ended December 31, 1996	1995	1994	Shares Outstanding December 31, 1996	Amount December 31, 1996 (in thousands)	1995
4-1/8%	$106.125	$100	233	-	-	119,767	$ 11,977	$ 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%	N/A	100	300,000	-	-	-	-	30,000
							$ 21,977	$ 52,000

. Cumulative Preferred Stock Subject to Mandatory Redemption:

Series(a)	Par Value	Shares Outstanding December 31, 1996	Amount December 31, 1996 (in thousands)	1995
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) 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) 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) 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) 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, 1996	December 31, 1995
	(in thousands)	
First Mortgage Bonds	$ 522,507	$ 562,017
Installment Purchase Contracts	309,120	308,971
Other Long-term Debt (a)	171,706	163,060
Junior Subordinated Deferrable Interest Debentures (b)	38,771	-
Sinking Fund Debentures (c)	-	6,053
	1,042,104	1,040,101
Less Portion Due Within One Year	-	6,053
Total	$1,042,104	$1,034,048

(a) Nuclear Fuel Disposal Costs including interest accrued. See Note 3.
(b) 8% - Due March 31, 2026 - $40,000,000 Outstanding less $1,228,500 discount.
(c) Called for redemption on March 1, 1996.

First mortgage bonds outstanding were as follows:

% Rate	Due	December 31, 1996	December 31, 1995
		(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
9.50	2021 - May 1	-	10,000
9.50	2021 - May 1	-	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)		(2,493)	(2,983)
Total		$522,507	$562,017

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, 1996	December 31, 1995
		(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:			
(a)	2014 - August 1	50,000	50,000
7.6	2016 - March 1	40,000	40,000
6.55	2025 - June 1	50,000	50,000
(b)	2025 - June 1	50,000	50,000
City of Sullivan, Indiana:			
5.95	2009 - May 1	45,000	45,000
Unamortized Discount		(2,880)	(3,029)
Total		$309,120	$308,971

(a) The variable interest rate is determined weekly. The average weighted interest rate was 3.5% for 1996 and 4.6% for 1995.
(b) The adjustable interest rate can be a daily, weekly, commercial paper or term rate as designated by the Company. A weekly rate was selected which ranged from 2.4% to 5.0% in 1996 and from 2.9% to 5% in 1995 and averaged 3.4% and 4.0% during 1996 and 1995, respectively.

Under the terms of certain installment purchase contracts, the Company is required to pay amounts sufficient to enable the cities to pay interest on and the principal (at stated maturities and upon mandatory redemption) of related pollution control revenue bonds issued to finance the construction of pollution control facilities at certain generating plants. On the two variable rate series the principal is payable at the stated maturities or on the demand of the bondholders at periodic interest adjustment dates which occur weekly. The variable rate bonds due in 2014 are supported by a bank letter of credit which expires in 2002. I&M has agreements that provide for brokers to remarket the adjustable rate bonds due in 2025 tendered at interest adjustment dates. In the event certain bonds cannot be remarketed, I&M has a standby bond purchase agreement with a bank that provides for the bank to purchase any bonds not remarketed. The purchase agreement expires in 2000. Accordingly, the variable and adjustable rate installment purchase contracts have been classified for repayment purposes based on the expiration dates of the standby purchase agreement and the letter of credit.

At December 31, 1996, future annual long-term debt payments, excluding premium or discount, are as follows:

	Principal Amount (in thousands)
1998	$ 35,000
1999	35,000
2000	50,000
2001	40,000
Later Years	888,706
Total	$1,048,706

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, 1996 and 1995 were available in the amounts of $409 million and $372 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, 1996:		
Note Payable	$ 3,900	5.5%
Commercial Paper	39,600	7.2
Total	$43,500	7.0
December 31, 1995:		
Note Payable	$52,200	6.1%
Commercial Paper	37,775	6.1
Total	$89,975	6.1

12. COMMON SHAREHOLDER'S EQUITY:

Mortgage indentures, charter provisions and orders of regulatory authorities place various restrictions on the use of retained earnings for the payment of cash dividends on common stock. At December 31, 1996, $5.9 million of retained earnings were restricted. Regulatory approval is required to pay dividends out of paid-in capital.

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

13. UNAUDITED QUARTERLY FINANCIAL INFORMATION:

Quarterly Periods Ended	Operating Revenues	Operating Income	Net Income
	(in thousands)		
1996			
March 31	$329,883	$53,018	$35,767
June 30	323,494	50,430	33,507
September 30	339,847	61,123	44,546
December 31	335,269	55,846	43,333
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

OPERATING STATISTICS

	1996	1995	1994	1993	1992
OPERATING REVENUES (in thousands):					
Retail:					
Residential:					
Without Electric Heating	$ 232,212	$ 239,266	$ 227,358	$ 205,315	$ 209,682
With Electric Heating	111,556	109,504	107,523	97,568	98,553
Total Residential	343,768	348,770	334,881	302,883	308,235
Commercial	253,750	256,319	247,938	220,938	228,285
Industrial	312,777	298,256	291,527	250,939	267,643
Miscellaneous	6,445	6,482	6,316	5,593	11,012
Total Retail	916,740	909,827	880,662	780,353	815,175
Wholesale (sales for resale)	391,478	357,441	352,889	404,910	369,379
Total Revenues from Energy Sales	1,308,218	1,267,268	1,233,551	1,185,263	1,184,554
Provision for Refunds of Revenues Collected in Prior Years	-	-	-	(755)	(4,038)
Total Net of Provision for Refunds	1,308,218	1,267,268	1,233,551	1,184,508	1,180,516
Other	20,275	15,889	17,758	18,135	16,239
Total Operating Revenues	$1,328,493	$1,283,157	$1,251,309	$1,202,643	$1,196,755
SOURCES AND USES OF ENERGY (in millions of kilowatthours):					
Sources:					
Net Generated:					
Fossil Fuel	13,304	12,850	13,022	12,236	11,597
Nuclear Fuel	16,396	13,999	9,291	16,313	6,418
Hydroelectric	99	86	95	106	100
Total Net Generated	29,799	26,935	22,408	28,655	18,115
Purchased and Power Pool	7,581	5,871	5,757	4,879	9,342
Total Sources	37,380	32,806	28,165	33,534	27,457
Less: Losses, Company Use, Etc.	1,795	1,700	1,398	1,349	1,466
Net Sources	35,585	31,106	26,767	32,185	25,991
Uses:					
Retail Sales:					
Residential:					
Without Electric Heating	3,329	3,390	3,210	3,178	3,001
With Electric Heating	1,811	1,768	1,727	1,706	1,633
Total Residential	5,140	5,158	4,937	4,884	4,634
Commercial	4,328	4,300	4,148	3,977	3,747
Industrial	7,295	6,582	6,453	6,025	5,685
Miscellaneous	82	82	82	83	194
Total Retail	16,845	16,122	15,620	14,969	14,260
Wholesale Sales (sales for resale)	18,740	14,984	11,147	17,216	11,731
Total Uses	35,585	31,106	26,767	32,185	25,991

OPERATING STATISTICS (Concluded)

	1996	1995	1994	1993	1992
AVERAGE COST OF FUEL CONSUMED (in cents):					
Per Million Btu:					
Coal	122	126	124	130	136
Nuclear	44	43	42	36	54
Overall	74	78	85	72	103
Per Kilowatthour Generated:					
Coal	1.22	1.23	1.21	1.27	1.34
Nuclear	.47	.47	.47	.40	.61
Overall	.80	.83	.90	.77	1.08

	1996	1995	1994	1993	1992
RESIDENTIAL SERVICE - AVERAGES:					
Annual Kwh Use per Customer:					
With Electric Heating	18,206	18,044	17,907	17,980	17,513
Total	10,791	10,943	10,572	10,559	10,107
Annual Electric Bill:					
With Electric Heating	$1,121.41	$1,117.55	$1,115.19	$1,028.26	$1,056.91
Total	$721.76	$739.99	$717.17	$654.76	$672.31
Price per Kwh (in cents):					
With Electric Heating	6.16	6.19	6.23	5.72	6.04
Total	6.69	6.76	6.78	6.20	6.65

	1996	1995	1994	1993	1992
NUMBER OF CUSTOMERS:					
Year-End:					
Retail:					
Residential:					
Without Electric Heating	378,757	375,929	372,473	369,385	366,835
With Electric Heating	100,372	99,105	97,402	95,795	94,175
Total Residential	479,129	475,034	469,875	465,180	461,010
Commercial	55,869	55,077	53,927	53,081	52,542
Industrial	5,345	5,316	5,213	5,157	5,000
Miscellaneous	1,820	1,797	1,806	1,783	1,751
Total Retail	542,163	537,224	530,821	525,201	520,303
Wholesale (sales for resale)	85	62	54	56	53
Total Electric Customers	542,248	537,286	530,875	525,257	520,356

DIVIDENDS AND PRICE RANGES OF CUMULATIVE PREFERRED STOCK
By Quarters (1996 and 1995)

	1996 - Quarters				1995 - 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	51	51-1/4	52	52	46-5/8	47-1/4	47-1/2	49-1/2
- Low	49-3/8	51	51-1/4	52	45-1/2	46-1/4	47-1/4	47-1/2
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	51	49	49-3/4	50	46-1/2	47	51	51
- Low	48-1/4	48-3/4	49	49-3/4	43	46	46	46
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	$1.5[illegible]
Market Price - $ Per Share (OTC)								
Ask (high/low)	-	-	-	-	-	-	-	-
Bid (high/low)	-	-	-	-	-	-	-	-
6.30% Series								
Dividends Paid Per Share	$1.575	$1.575	$1.575	$1.575	$1.575	$1.575	$1.575	$1.575
Market Price - $ Per Share (OTC)								
Ask (high/low)	-	-	-	-	-	-	-	-
Bid (high/low)	-	-	-	-	-	-	-	-
6-7/8% Series								
Dividends Paid Per Share	$1.71875	$1.71875	$1.71875	$1.71875	$1.71875	$1.71875	$1.71875	$1.71875
Market Price - $ Per Share (OTC)								
Ask (high/low)	-	-	-	-	-	-	-	-
Bid (high/low)	-	-	-	-	-	-	-	-
7.08% Series (a)								
Dividends Paid Per Share	$1.77				$1.77	$1.77	$1.77	$1.77
Market Price - $ Per Share								
(NYSE) - High	-				83-5/8	88-1/2	91	99-1/2
- Low	-				76	84	86	86

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

SECURITY OWNER INQUIRIES

Security owners should direct 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 1997 at no cost to shareholders. Please address requests for copies to:

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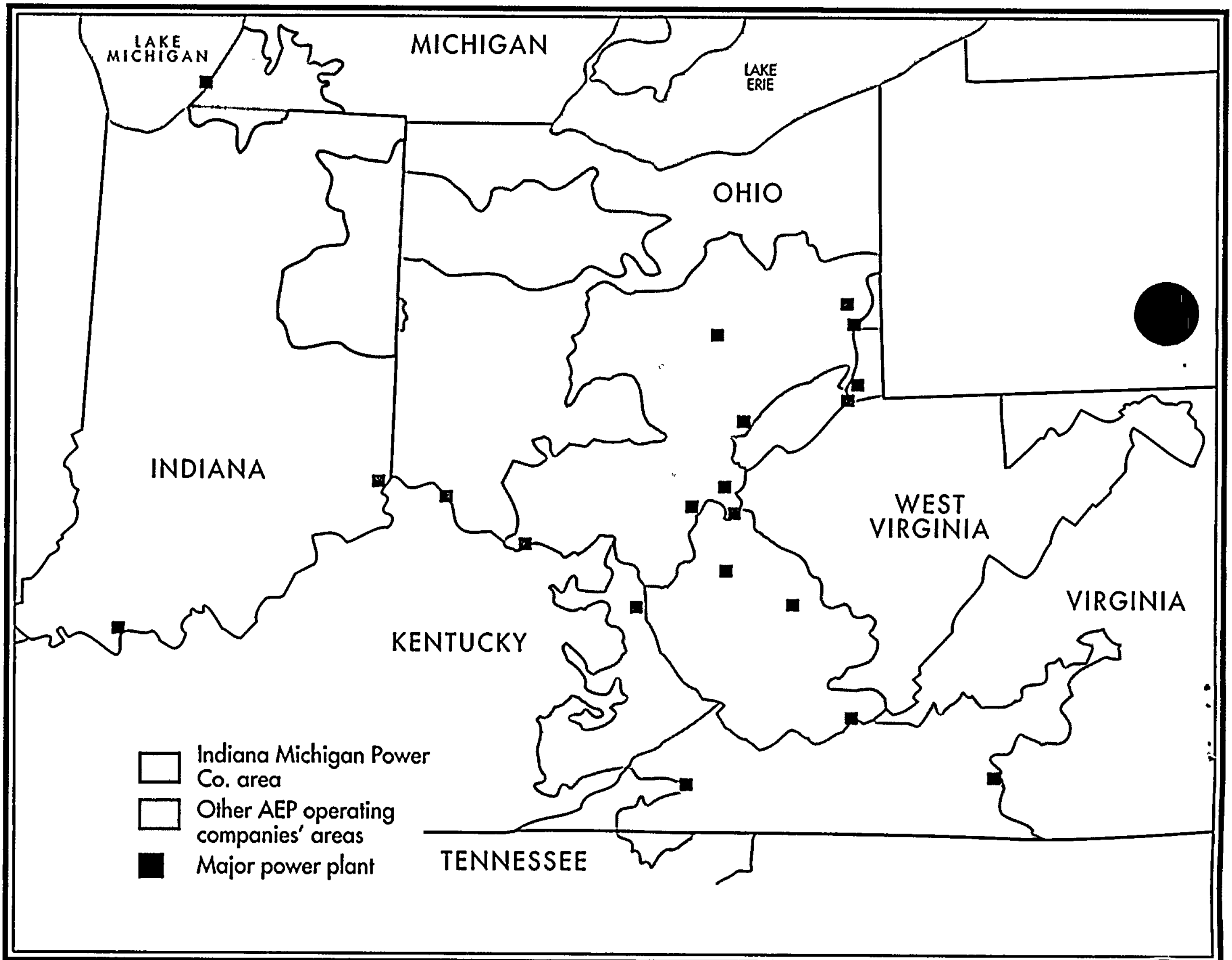
TRANSFER AGENT AND REGISTRAR OF CUMULATIVE PREFERRED STOCK

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:0909M

INDIANA MICHIGAN POWER COMPANY'S
PROJECTED CASH FLOW FOR 1997

Indiana Michigan Power Co.
1997 Forecasted Sources and Uses of Funds
Based on Forecasted Case 9701

$ Millions

	Projected 1997
Net Income After Taxes	170.8
Less Dividends Paid	121.8
Retained Earnings	49.0
Adjustments:	
Depreciation And Amortization	161.6
Deferred Operating Costs	11.3
Deferred Federal Income Taxes and Investment Tax Credits	(11.3)
AFUDC	(1.0)
Other	(21.7)
Total Adjustments	138.9
Internal Cash Flow	187.9
Average Quarterly Cash Flow	47.0
Average Cash Balances and Short-Term Investments	15.3
Total	62.3