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SUBJECT: Forwards financial info from annual rept for 1991 & projected cash flow for 1992.

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P.O. Box 16631
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INDIANA
MICHIGAN
POWER

AEP:NRC:0909H
10 CFR 50.71(b) & 140.21(e)

Donald C. Cook Nuclear Plant Unit Nos. 1 and 2
Docket Nos. 50-315 and 50-316
License Nos. DPR-58 and DPR-74
FINANCIAL INFORMATION FOR INDIANA MICHIGAN
POWER COMPANY

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

Attn: T. E. Murley

April 15, 1992

Dear Dr. Murley:

Enclosure 1 contains the Indiana Michigan Power Company's (I&M) annual report for 1991. Enclosure 2 contains a copy of I&M's projected cash flow for 1992. These reports are submitted pursuant to 10 CFR 50.71(b) and 10 CFR 140.21(e).

This document has been prepared following Corporate procedures that incorporate a reasonable set of controls to ensure its accuracy and completeness prior to signature by the undersigned.

Sincerely,

E E Fitzpatrick

E. E. Fitzpatrick
Vice President

dfw
Enclosures

cc: D. H. Williams, Jr.
A. A. Blind - Bridgman
J. R. Padgett
G. Charnoff
A. B. Davis - Region III
NRC Resident Inspector - Bridgman
NFEM Section Chief

M004 1/1

ENCLOSURE 1 TO AEP:NRC:0909H

INDIANA MICHIGAN POWER COMPANY'S

1991 ANNUAL REPORT

Indiana Michigan Power Company

1991 Annual Report

AEP AMERICAN ELECTRIC POWER

Contents

Background of the Company

INDIANA MICHIGAN POWER COMPANY (the Company), a subsidiary of American Electric Power Company, Inc. (AEP), is engaged in the generation, purchase, transmission and distribution of electric power. The Company was organized under the laws of Indiana on February 21, 1925, and is also authorized to transact business in Michigan and West Virginia. Its principal executive offices are in Fort Wayne, Indiana.

The Company has two wholly owned subsidiaries; they are Blackhawk Coal Company and Price River Coal Company, which were formerly engaged in coal-mining operations. 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 generating plants of the Company and affiliates. RTD also provides some barging services to unaffiliated companies.

The Company serves approximately 483,000 customers in northern and eastern Indiana and a portion of southwestern Michigan. Among the principal industries served are transportation equipment, primary metals, fabricated metal products, electrical and electronic machinery, and chemicals and allied products. In addition, the Company supplies wholesale electric power to other electric utilities, municipalities and electric cooperatives.

The Company's generating plants and important load centers are interconnected by a high-voltage transmission network. This network in turn is interconnected either directly or indirectly with the following other AEP System companies to form a single integrated power system: AEP Generating Company, Appalachian Power Company, Columbus Southern Power Company, Kentucky Power Company, Kingsport Power Company, Michigan Power Company, Ohio Power Company and Wheeling Power Company. The Company is also interconnected with the following unaffiliated utilities: 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 & 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). The Company shares generating and transmission capacity and the cost of such capacity with the other affiliated AEP System companies through the AEP System Power Pool and AEP Transmission Agreement.

Directors

Mark A. Bailey
Richard E. Disbrow
William N. D'Onofrio
E. Linn Draper, Jr. (a)
Allen R. Glassburn (b)
William J. Lhota
Gerald P. Maloney
Richard C. Menge
Dwight I. Pittenger (b)
William F. Pohlman (c)
Ronald E. Prater (c)
Dale M. Trenary (b)
William E. Walters (c)
W. S. White, Jr. (d)
David H. Williams, Jr.

Officers

W. S. White, Jr. (d)
Chairman of the Board

Richard E. Disbrow (e)
Chairman of the Board and Chief Executive Officer

Richard C. Menge
President and Chief Operating Officer

Milton P. Alexich (f)
Vice President

Mark A. Bailey
Vice President

Peter J. DeMaria (g)
Vice President and Treasurer

William N. D'Onofrio
Vice President

A. Joseph Dowd
Vice President

E. Linn Draper, Jr. (a)
Vice President

Eugene E. Fitzpatrick (h)
Vice President

Richard F. Hering
Vice President

William J. Lhota
Vice President

Gerald P. Maloney
Vice President

David H. Williams, Jr.
Vice President

John F. DiLorenzo, Jr.
Secretary

Elio Bafile
Assistant Secretary and Assistant Treasurer

Jeffrey D. Cross
Assistant Secretary

Carl J. Moos
Assistant Secretary

John B. Shinnock
Assistant Secretary

Leonard V. Assante
Assistant Treasurer

Bruce M. Barber
Assistant Treasurer

Gerald R. Knorr
Assistant Treasurer

As of January 1, 1992 the current directors and officers of Indiana Michigan Power Company were employees of American Electric Power Service Corporation with eight exceptions: Messrs. Bafile, Bailey, D'Onofrio, Menge, Moos, Pohlman, Prater, and Walters, who were employees of Indiana Michigan Power Company.

(a) Elected effective March 1, 1992
(b) Resigned April 23, 1991
(c) Elected April 23, 1991
(d) Resigned December 31, 1991
(e) Elected Chairman of the Board December 31, 1991
(f) Resigned April 1, 1991
(g) Elected Vice President April 23, 1991
(h) Elected April 1, 1991

Selected Consolidated Financial Data

	Year Ended December 31,				
	1991	1990	1989	1988	1987
			(in thousands)		
INCOME STATEMENTS DATA:					
Operating Revenues	**$1,211,607**	$1,257,089	$1,121,407	$1,053,994	$1,078,330
Operating Expenses	**987,297**	1,058,953	911,011	838,551	855,284
Operating Income	**224,310**	198,136	210,396	215,443	223,046
Nonoperating Income (Loss)	**(3,699)**	7,592	32,930	43,454	56,828
Income Before Interest Charges	**220,611**	205,728	243,326	258,897	279,874
Interest Charges	**85,325**	89,413	106,181	107,092	113,508
Net Income	**135,286**	116,315	137,145	151,805	166,366
Preferred Stock Dividend Requirements	**15,417**	15,587	18,048	18,848	20,955
Earnings Applicable to Common Stock	**$ 119,869**	$ 100,728	$ 119,097	$ 132,957	$ 145,411

	December 31,				
	1991	1990	1989	1988	1987
			(in thousands)		
BALANCE SHEETS DATA:					
Electric Utility Plant	**$4,078,336**	$4,011,464	$3,918,616	$4,411,271	$4,153,281
Accumulated Depreciation and Amortization	**1,503,761**	1,403,871	1,292,430	1,218,060	1,118,254
Net Electric Utility Plant	**$2,574,575**	$2,607,593	$2,626,186	$3,193,211	$3,035,027
Total Assets	**$3,573,847**	$3,599,669	$4,229,812	$3,966,277	$3,920,163
Common Stock and Paid-in Capital	**$ 774,193**	$ 774,193	$ 774,193	$ 838,347	$ 828,347
Retained Earnings	**164,166**	145,489	157,825	161,443	145,302
Total Common Shareowner's Equity	**$ 938,359**	$ 919,682	$ 932,018	$ 999,790	$ 973,649
Cumulative Preferred Stock:					
Not Subject to Mandatory Redemption	**$ 197,000**	$ 197,000	$ 197,000	$ 197,000	$ 197,000
Subject to Mandatory Redemption (a)	**—**	—	18,030	25,030	32,030
Total	**$ 197,000**	$ 197,000	$ 215,030	$ 222,030	$ 229,030
Long-term Debt (a)	**$1,120,709**	$1,123,833	$1,522,736	$1,575,220	$1,591,768
Obligations Under Capital Leases (a)	**$ 102,511**	$ 133,064	$ 122,977	$ 167,920	$ 170,830
Total Capitalization and Liabilities	**$3,573,847**	$3,599,669	$4,229,812	$3,966,277	$3,920,163

(a) Including portion due within one year.

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

Results of Operations

Net Income Increases

Net income increased 16% to $135 million in 1991 after decreasing 15% in 1990 to $116 million. The increase in 1991 was predominantly due to reductions in fuel expense, energy purchases and maintenance expense, reflecting the fact that neither of the Company's two nuclear generating units were refueled during 1991 and decreased interest charges, partially offset by a decline in demand for wholesale energy. The decrease in 1990 was primarily due to a decline in accruals for allowance for funds used during construction (AFUDC) as a result of the commercial operation of Rockport Plant Unit 2 (Rockport 2) in December 1989 and increased operating and maintenance costs related to the refueling outages at the nuclear units. In 1989 net income decreased $15 million from 1988 primarily due to the effects of refueling outages for the two nuclear units.

Outlook

The Company faces a number of challenges that could adversely affect the Company's financial performance and possibly its ability to meet its financial obligations and commitments. While management believes the Company is equipped to deal with the future, uncertainties that could adversely affect the Company's future financial performance include the ability to obtain favorable rate-making treatment to recover from ratepayers on a timely basis its cost of service, including the cost of compliance with the Clean Air Act Amendments of 1990 and other environmental costs under present and future laws and regulations.

In addition, the Company's results could be negatively affected by: (a) the recession, especially if it were to deepen and impact the Company's highly industrialized service territory; (b) increased competition in the wholesale electric energy market; and (c) unseasonably mild weather. With its large industrial base, results of operations for the Company are sensitive to economic conditions which can also be impacted by inflation, foreign currency fluctuations and the market price of primary metals. Unfortunately these items are not generally within management's control.

The ability of the American Electric Power System Power Pool (Power Pool) to make wholesale sales, which the Company shares in, equal to or greater than the level of such sales reflected in the Company's rates will affect future results of operations. The Power Pool will make every effort to continue marketing available capacity in the near term. In addition, management will be devoting particular attention in 1992 toward the reduction of growth in its cost of service and the finalization of a plan to comply with the Phase I requirements of the Clean Air Act Amendments of 1990.

Revenues and Energy Sales Decline

Operating revenues declined $45 million in 1991 following increases of $136 million and $67 million in 1990 and 1989, respectively. The significant fluctuation in operating revenues reflects the volatility of the Power Pool's wholesale sales. The decline in 1991 revenues was due to price competition in the wholesale energy market and the continued decline in wholesale sales by the Power Pool to unaffiliated utilities which began in the fourth quarter of 1990. The significant increase in 1990 revenues was attributable to increased wholesale sales to unaffiliated utilities in the first three quarters of 1990 and the commercial operation of Rockport 2 in December 1989 resulting in the Company receiving capacity payments from the AEP System Power Pool. The increase in 1989 revenues resulted from the increased short-term wholesale sales. The changes in revenues can be analyzed as follows:

	Increase (Decrease) From Previous Year					
(dollars in millions)	1991		1990		1989	
	Amount	%	Amount	%	Amount	%
Retail:						
Price variance	$ (1.2)		$ (8.1)		$(18.5)	
Volume variance	27.1		(8.4)		10.0	
	25.9	3.7	(16.5)	(2.3)	(8.5)	(1.2)
Wholesale:						
Price variance	(54.0)		71.1		(94.6)	
Volume variance	(27.0)		83.8		166.0	
	(81.0)	(14.9)	154.9	39.6	71.4	22.4
Other Operating Revenues	9.6		(2.7)		4.5	
Total	$(45.5)	(3.6)	$135.7	12.1	$ 67.4	6.4

The increase in 1991 retail sales volume reflects a return to more seasonable weather patterns with a warmer spring and summer, partially offset by a decrease in industrial sales volume caused by the transfer of service of a major industrial customer to a local distribution utility which is served as a wholesale customer. The slight decrease in 1990 retail sales volume reflects the effects of mild weather on residential sales. A modest increase in 1989 retail sales volume reflects growth in the number of customers and increased commercial development. Growth in electric heating and cooling load has made results of operations more sensitive to weather.

The negative wholesale volume variance in 1991 reflects a substantial decrease in Power Pool wholesale sales. A Power Pool long-term contract for the sale of up to 560 mw of power to an unaffiliated utility expired on December 31, 1990. Also during 1990 the Power Pool sold significant quantities of energy to a Canadian utility under a series of short-term wholesale contracts which expired at the end of 1990. Management has sought to make short-term sales but has had limited success due to the highly competitive nature of the energy market and its dependence on factors, such as the increased availability of unaffiliated generating capacity and economic conditions, which are not generally within management's control.

The increase in 1990 wholesale sales volume was predominantly due to the commencement in January 1990 of a 250 megawatt (mw) long-term Rockport 2 unit power sales agreement and increased sales of energy to affiliated and unaffiliated utilities with increased capacity from Rockport 2, including the sale by the Power Pool of substantial short-term energy to a Canadian utility. The lack of available unaffiliated generating capacity throughout most of 1989, a reduction by the Power Pool of its short-term energy prices and extremely cold weather in December 1989 combined to produce a significant increase in 1989's short-term wholesale sales compared with 1988.

Operating Expenses Decline

Operating expenses decreased nearly 7% in 1991 due to reduced fuel expense, energy purchases and maintenance expense reflecting the return to service of the Company's nuclear generating units and decreased demand for wholesale energy. Operating expenses increased 16% in 1990 and nearly 9% in 1989 due to increased wholesale sales and nuclear plant maintenance. The addition of Rockport 2 generating capacity also contributed to the 1990 increase. Changes in the components of operating expenses were as follows:

	Increase (Decrease) From Previous Year					
(dollars in millions)	1991		1990		1989	
	Amount	%	Amount	%	Amount	%
Fuel	$(25.4)	(9.2)	$ 26.8	10.7	$16.9	7.3
Purchased and Interchange Power (net)	(40.1)	(24.7)	21.5	15.3	22.7	19.2
Other Operation	(2.2)	(0.9)	73.5	43.0	9.3	5.8
Maintenance	(17.4)	(13.0)	30.3	29.1	14.7	16.4
Depreciation and Amortization	1.0	0.7	4.3	3.0	3.5	2.6
Taxes Other Than Federal Income Taxes	6.7	12.2	(2.0)	(3.5)	0.1	0.2
Federal Income Taxes	5.8	14.4	(6.5)	(14.0)	5.2	12.4
Total	$(71.6)	(6.8)	$147.9	16.2	$72.4	8.6

Although generation increased by 8% in 1991, fuel expense declined 9% due to a shift in the generation mix from relatively higher cost coal-fired generation to lower cost nuclear generation coupled with a decreased average cost of fuel consumed. The increase in 1990 and 1989 fuel expense reflects higher net generation resulting from the commercial operation of Rockport 2 in December 1989 and the substantial increase in wholesale demand of unaffiliated utilities.

Purchased and interchange power expense generally varies directly with Power Pool wholesale sales since many of the wholesale sales result from purchases of power from unaffiliated utilities for immediate resale to other unaffiliated utilities. The decrease in 1991 reflects the decline in wholesale power demand while the 1990 and 1989 increases reflected higher levels of wholesale power transactions.

The significant increase in other operation expense in 1990 was primarily due to lease expense on Rockport 2 which was sold and leased back in December 1989. In addition, the increase in other operation expense and maintenance expense in 1990 and 1989 was due to scheduled refueling outages of both of the Company's nuclear generating units. In the second half of 1990, both units were out of service for several months each for scheduled refueling. In 1989, Unit 1 was refueled and Unit 2 was out of service to replace its steam generators, refuel and conduct a 10-year service inspection as required by the Nuclear Regulatory Commission. The units are generally refueled on an approximately 18-month cycle. The comparative decrease in maintenance expense in 1991 reflects the fact that the Company's two nuclear units were in service almost all of 1991. Prior to the replacement of Unit 2's steam generators the refueling schedule required only one unit to be out of service per year. Both units are scheduled for refueling outages in 1992. In order to mitigate the fluctuation of earnings that will result from the new refueling schedule management has petitioned its applicable regulatory commissions to permit the deferral of incremental refueling outage costs for amortization over the period between outages. The Indiana Utility Regulatory Commission (IURC) has approved the Company's request.

A combination of stricter regulatory requirements for maintenance and training and the limited supply of nuclear grade materials for replacement parts has contributed to nuclear industry operation and maintenance expenses increasing at a rate higher than the general inflation rate. Industry efforts are underway to change this trend. As the Company's two nuclear units, which were placed in service in 1975 and 1978, continue to age, the Company expects to incur increasing operation and maintenance costs.

Taxes other than Federal income taxes increased in 1991 primarily due to the effect of a property tax over accrual adjustment recorded in 1990 and a provision recorded in 1991 for an audit assessment of Indiana gross receipts tax on payments received under the AEP System transmission equalization agreement.

The increase in 1991 Federal income tax expense attributed to operations was primarily due to the increase in pre-tax operating book income offset in part by changes in items included in 1991 operating book income which were not included in the Federal tax return. The 1990 decrease in Federal income tax expense was primarily due to adjustments relating to prior years' tax returns and an increase in the amortization of deferred investment tax credits due predominantly to placing Rockport 2 in service. The increase in Federal income tax expense in 1989 was primarily due to changes in certain book/tax timing differences accounted for on a flow-through basis.

Nonoperating Income and Interest Charges

Nonoperating income declined in 1991 due to a $3.2 million after-tax provision for a loss which may result from a royalty dispute with the state of Utah concerning prior coal mining operations and a $2.3 million after-tax write-off of the costs associated with a Federal coal lease of a currently inactive subsidiary. Interest income from temporary investments decreased in 1991 compared with 1990 when the Company invested part of the proceeds from the sale of Rockport 2 until it retired debt, redeemed preferred stock and paid taxes related to the sale.

AFUDC decreased substantially in 1990 since accruals on Rockport 2 ceased effective with its commercial operation on December 1, 1989. The increase in 1989's AFUDC reflected the additional accumulated Rockport 2 construction expenditures. The 1989 nonoperating income decrease was the result of a one-time credit to income in the fourth quarter of 1988 to record, in accordance with Federal Energy Regulatory Commission (FERC) guidance, the interest accrued on nuclear decommissioning trust funds since their inception.

The decline in interest charges on long-term debt in 1991 was due to the retirement of debt in February 1990 with proceeds from the sale of Rockport 2, the refinancing of Installment Purchase Contracts (IPC) at lower rates and a lower average interest rate on the variable IPC partially offset by increased interest on short-term borrowings incurred in 1991 to meet temporary cash requirements. The reduction in interest charges on long-term debt in 1990 was primarily due to the repayment of first mortgage bonds with the Rockport 2 proceeds.

Liquidity and Capital Resources

Construction Spending Drops

Gross plant and property additions dropped to $145 million in 1991 and $162 million in 1990 from $206 million in 1989 primarily reflecting the completion of Rockport 2 and the replacement of one unit's steam generator at the Company's nuclear plant. Construction expenditures for the next three years are estimated at $438 million, exclusive of yet to be determined additional expenditures necessary to meet the requirements of the Clean Air Act Amendments of 1990. The Company funds its substantial annual capital requirements for construction of new facilities and improvement of existing facilities through a combination of internally generated funds, short-term and long-term borrowings and investments in its common equity by its parent, AEP. Approximately 92% of the Company's construction expenditures for the next three years, exclusive of any expenditures necessary to meet the requirements of the Clean Air Act Amendments of 1990, are expected to be financed internally.

Capital Resources

The Company generally issues short-term debt to provide for interim financing of construction and capital expenditures in excess of available internally generated funds. The Company has increased its short-term borrowings by $10 million and $34 million in the last two years primarily to fund capital improvements and decreased its short-term debt by $36 million in 1989 reflecting the repayment of debt with some of the proceeds from the Rockport 2 sale. At December 31, 1991, the Company had available unused short-term lines of credit of $374 million shared with other AEP System companies. Regulatory provisions limit short-term debt borrowings to $200 million and a charter provision further limits short-term borrowings to $130 million. The Company periodically reduces its outstanding short-term debt through the issuance of long-term debt and preferred stock securities and investments in its common equity by AEP.

The Company is seeking regulatory authority to issue up to $150 million of long-term debt. The proceeds are expected to be used to refinance $25 million of 8½% installment purchase contracts, retire short-term debt and fund construction expenditures.

Generally, in order to issue long-term debt without refunding an equal amount of existing debt, the Company must have pre-tax earnings equal to at least twice annual interest charges on long-term debt after giving effect to the issuance of the new debt. To issue additional preferred stock, the Company must have after-tax gross income at least equal to one and one-half times annual interest and preferred dividend requirements after giving effect to the issuance of the new preferred stock. As a result, the earnings performance of the Company will determine its ability to finance, which, in turn, will determine its ability to fund construction. As of December 31, 1991, the Company's long-term debt and preferred stock coverage ratios were 4.19 and 2.24, respectively.

Concerns and Contingencies

Environmental Costs — Clean Air Act Amendments of 1990

In November 1990 the Clean Air Act Amendments became law. They require, among other things, substantial reductions in allowable levels of sulfur dioxide and nitrogen oxide emissions from coal-fired electric generating plants and place a permanent nationwide limit on sulfur dioxide emissions after 1999. The Amendments establish a strict timetable for compliance, setting a deadline of 1995 for the first phase of reductions and 2000 for the second phase. Although the AEP System has in the past made substantial expenditures to satisfy the provisions of clean air laws, the System will have to adopt substantial additional measures to comply with the Amendments. The compliance alternatives being considered for the AEP System include: (a) installation of sulfur dioxide and nitrogen oxide emissions reduction equipment on affected generating units which would require substantial capital expenditures and result in significantly increased operating costs and reduced generating efficiency; (b) switching to lower sulfur coal or natural gas, resulting in adverse impacts on affiliated mining operations and related facilities and less substantial capital expenditures; and (c) premature retirement of certain existing generating units. The Company's Cook Nuclear Plant is not affected by the new legislation. Additionally, the Company's Rockport Plant and three of the four units at its Tanners Creek Plant, all of which burn low sulfur coal, are currently in compliance with the new law. Alternatives to meet the new requirements at the Company's coal-fired Tanners Creek Unit 4 are being studied. The Company has announced the retirement of the Breed Plant no later than the end of 1994. The 31 year age of the plant and a deteriorating boiler requiring costly repairs have made it economically impractical to operate the unit full time and to meet the requirements of the Clean Air Act Amendments. As a member of the Power Pool the Company could be impacted by the cost of compliance at generating units owned by other Power Pool member companies. Management intends to seek recovery of any compliance costs. The Company's cost of compliance could adversely affect results of operations and financial condition if not recovered through the rate-making process.

Hazardous Material

The generation of electricity unavoidably produces a number of non-hazardous and hazardous materials such as ash, slag, sludge, low level radioactive waste, spent nuclear fuel, etc. In addition the Company's generating plants and transmission/distribution facilities have used asbestos, polychlorinated biphenyls (PCB's) and other hazardous materials. The Company incurs significant costs to store and dispose of hazardous materials in accordance with current laws and regulations. Additional compliance efforts and costs could be incurred to meet the requirements of new laws and regulations.

The Comprehensive Environmental Response Compensation and Liability Act (Superfund) established programs dealing with clean-up of hazardous waste disposal sites, as well as other matters, and authorized the U.S. Environmental Protection Agency (EPA) to administer them. The Company has been named by the EPA as a "potentially responsible party" (PRP) for seven sites and has received information requests for two other sites. The Company has also been identified as a PRP under Illinois law for one additional site. For two of these sites the Company's liability has been settled for an insignificant amount. Although the potential liability associated with each PRP has been and must be evaluated individually, several general statements can be made regarding the PRP notices the Company has received. The claim that the Company disposed of hazardous waste at a site is often unsubstantiated, the quantity of material disposed of at a site was generally minor and/or the nature of the material the Company generally disposed of at such site was non-hazardous. Typically the Company is one of many parties named as PRP's for a site and, although liability is joint and several, at least several of the other parties are generally financially sound enterprises. Therefore the Company's present estimates do not anticipate material clean up costs. However, should material costs be required, the Company's results of operations and financial condition could be adversely impacted unless the costs can be recovered from insurance and/or ratepayers.

The Company maintains insurance against damage and liability from its nuclear plant. In the event of a nuclear incident at the Company's nuclear plant or any nuclear plant in the United States the insurance program would require the Company to pay significant retrospective premiums. In addition the Company may incur additional uninsured costs. If not recovered from ratepayers, such costs could adversely impact results of operations and financial condition.

The Company has a significant liability for decommissioning of its nuclear plant and demolition of its coal-fired plants. The Company is recording a provision for such decommissioning and demolition commensurate with recovery through rates. The regulators have authorized recovery of nuclear decommissioning costs over the life of the plant based on an independent 1989 study which estimated decommissioning to cost between $330 million and $369 million. Recently however, a new study was performed which estimated that the cost of decommissioning ranges from $588 million to $1,102 million. The substantial increase in the cost is primarily due to the possible need to store spent nuclear fuel at the plant site for an extended time after the plant ceases operation delaying the commencement of dismantling activities. Variables in the length of time spent nuclear fuel must be stored at the plant subsequent to ceasing operations, which is dependent on future developments in the U.S. Department of Energy's program for disposal of spent nuclear fuel, have widened the range of the estimate. Management plans to seek an appropriate increase in the level of collections for decommissioning expense. Management will continue to periodically reevaluate the cost of decommissioning and to seek regulatory approval to revise rates as necessary.

Low Level Radioactive Waste Disposal

Under Federal law, states can enter into regional compacts to provide for the disposal of low level radioactive waste. Membership for the state of Michigan in the Midwest Compact has been revoked for its failure to meet host state obligations. The Company's nuclear plant is located in Michigan. As a result, the nuclear plant has been denied access since November 1990 to currently operating low level radioactive waste disposal sites and its low level radioactive waste is being stored in a facility at the plant site. The Company is constructing an additional facility at its nuclear plant (with completion scheduled for 1992) for temporary storage of the plant's low level radioactive waste. The on-site storage facility is expected to provide ample temporary space for a number of years. The long-term effects on the Company of the revocation of Michigan's membership in the Midwest Compact cannot be predicted presently.

Other New Environmental and Health Concerns

In recent years there has been considerable discussion of the potential for global climate change due to the emission of carbon dioxide into the atmosphere and the effects on public health of electric and magnetic fields (EMF) from transmission and distribution facilities. Management is concerned that new laws may be passed or new regulations promulgated without sufficient scientific study and support. The Company will be working to support further efforts to properly study the issues of global climate change and EMF to define the extent, if any, to which they pose a threat to the environment and public health before new restrictions are imposed. Should Congress enact legislation to address these issues, the Company's results of operations and financial condition could be adversely affected unless the cost of compliance can be recovered from ratepayers.

Regulatory Matters

During 1991 the IURC issued orders granting the Company additional net annual revenues totaling approximately $4 million. These orders stem from a rate proceeding that began in July 1989 when the Company requested an annual increase of $60 million. In 1990, the IURC had granted the Company $19 million of the requested increase.

In November 1991 the Company filed notice of its intent to seek additional rate relief in its Indiana retail jurisdiction during 1992. The request will seek recovery of increased operating costs including increased nuclear decommissioning cost estimates as discussed above and postretirement benefits other than pensions discussed in a later section.

In February 1991 the Michigan Public Service Commission (MPSC) approved a settlement agreement granting the Company a $7.4 million increase in April 1991 and an additional $3 million increase effective April 1992. The settlement agreement resulted from a request filed by the Company in June 1990 seeking an annual increase in Michigan retail rates of $16 million.

In June 1991 the FERC approved a final settlement agreement granting the Company a $4 million annual wholesale rate increase. The settlement agreement was the result of a request filed in March 1990 seeking an annual rate increase of $11 million.

In 1990 an initial decision was issued by a FERC administrative law judge regarding a complaint filed by a wholesale customer concerning the reasonableness of the Company's coal costs and the coal transportation charges of affiliates. The initial decision would require the Company to refund to wholesale customers $25 million related to coal costs and a yet to be determined amount of affiliated transportation charges. The Company has filed exceptions to the initial decision and the matter is subject to a final decision of the full Commission.

Merger

During 1991 the Company and Michigan Power Company (MPCo), an affiliate, filed with the IURC, MPSC, Securities and Exchange Commission (SEC) and FERC. The applications were filed pursuant to a settlement agreement previously approved by the MPSC. The applications sought approval in connection with the merger of MPCo into the Company with the surviving entity (the Company) to have all the rights, privileges and obligations of both companies prior to the merger. All applicable regulatory authorities approved the merger which became effective February 29, 1992. The merger will be accounted for as a pooling-of-interests. For the year ended December 31, 1991, operating revenues, net income and earnings applicable to common stock would have been $1,226 million, $137 million and $122 million, respectively, if the merger had occurred during the year. The merger will not significantly impact results of operations or financial condition.

Effects of Inflation

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

New Accounting Standards

The Financial Accounting Standards Board's (FASB) new accounting standard, Statement of Financial Accounting Standards (SFAS) 109 *Accounting for Income Taxes,* supersedes SFAS 96 and will require the Company to adopt the liability method of accounting for income taxes in 1993. SFAS 109 will result in a significant increase in total assets and liabilities due to the recording of deferred income taxes on temporary differences previously flowed through and of corresponding offsetting regulatory assets and liabilities. In addition, existing deferred taxes will be adjusted to the level required at the then-current statutory tax rate. Whether the Company implements the new standard on a restated or prospective basis has not yet been determined. It is not presently anticipated that the implementation of the new standard will significantly impact results of operations and financial condition.

The FASB issued an accounting standard in December 1990 that requires a change in accounting for postretirement benefits other than pensions from an expense-as-paid method to an accrual method effective in 1993. This standard permits an initial year recognition of the entire prior service costs or their accrual as a transition obligation over periods of up to 20 years. The Company expects to elect the 20-year transition option to comply with the new standard. The Company amended its other post-retirement plan effective January 1992. The annual expense, inclusive of the plan changes, required by the new standard is expected to be approximately three times the current pay-as-you-go expense and the transition obligation is estimated to be between $80 million and $90 million. The Company plans to seek recovery of the increased expense in its next base rate filings and to request authority before January 1, 1993 to defer under the provisions of SFAS 71 any increased costs for which recovery is not provided currently. Although the Company expects to file a rate case in its Indiana jurisdiction in the second quarter of 1992, the Company is unable to determine if the rate proceeding will be concluded by the January 1, 1993 effective date. Should recovery of or a commitment to allow future recovery of these new accruals be denied, the Company's results of operations and possibly its financial condition would be adversely impacted.

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Touche

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INDEPENDENT AUDITORS' REPORT

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

We have audited the accompanying consolidated balance sheets of Indiana Michigan Power Company and its subsidiaries as of December 31, 1991 and 1990, and the related consolidated statements of income, retained earnings, and cash flows for each of the three years in the period ended December 31, 1991. 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, 1991 and 1990, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1991 in conformity with generally accepted accounting principles.

Deloitte & Touche

February 25, 1992

Member
DRT International

Consolidated Statements of Income

	Year Ended December 31, 1991	1990	1989
		(in thousands)	
OPERATING REVENUES	**$1,211,607**	$1,257,089	$1,121,407
OPERATING EXPENSES:			
Fuel	**251,325**	276,719	249,886
Purchased and Interchange Power (net)	**122,573**	162,676	141,145
Other Operation	**242,161**	244,382	170,855
Maintenance	**117,100**	134,521	104,223
Depreciation and Amortization	**130,132**	129,091	124,809
Amortization of Rockport Plant Unit 1 Phase-in Costs	**16,961**	16,961	16,961
Taxes Other Than Federal Income Taxes	**61,049**	54,389	56,377
Federal Income Taxes	**45,996**	40,214	46,755
Total Operating Expenses	**987,297**	1,058,953	911,011
OPERATING INCOME	**224,310**	198,136	210,396
NONOPERATING INCOME (LOSS):			
Allowance for Equity Funds Used During Construction	**966**	1,174	27,972
Other	**(4,665)**	6,418	4,958
Total Nonoperating Income (Loss)	**(3,699)**	7,592	32,930
INCOME BEFORE INTEREST CHARGES	**220,611**	205,728	243,326
INTEREST CHARGES:			
Long-term Debt	**82,172**	87,385	131,009
Short-term Debt and Other	**4,293**	3,507	7,279
Allowance for Borrowed Funds Used During Construction	**(1,140)**	(1,479)	(32,107)
Net Interest Charges	**85,325**	89,413	106,181
NET INCOME	**135,286**	116,315	137,145
PREFERRED STOCK DIVIDEND REQUIREMENTS	**15,417**	15,587	18,048
EARNINGS APPLICABLE TO COMMON STOCK	**$ 119,869**	$ 100,728	$ 119,097

See Notes to Consolidated Financial Statements.

Consolidated Balance Sheets

	December 31, 1991	December 31, 1990
	(in thousands)	
ASSETS		
ELECTRIC UTILITY PLANT:		
Production	$2,524,826	$2,473,678
Transmission	807,555	778,115
Distribution	510,923	482,324
General (includes nuclear fuel)	152,740	182,906
Construction Work in Progress	82,292	94,441
Total Electric Utility Plant	4,078,336	4,011,464
Accumulated Depreciation and Amortization	1,503,761	1,403,871
Net Electric Utility Plant	2,574,575	2,607,593
OTHER PROPERTY AND INVESTMENTS	369,925	347,381
CURRENT ASSETS:		
Cash and Cash Equivalents	11,605	2,721
Accounts Receivable:		
Customers	61,301	70,677
Affiliated Companies	38,791	26,926
Miscellaneous	27,078	25,237
Allowance for Uncollectible Accounts	(589)	(674)
Fuel — at average cost	59,148	54,790
Materials and Supplies — at average cost	48,539	38,483
Accrued Utility Revenues	36,184	39,085
Other	7,911	7,786
Total Current Assets	289,968	265,031
DEFERRED CHARGES:		
Taxes — Gain on Sale and Leaseback of Rockport Plant Unit 2	169,874	176,967
Depreciation and Return — Rockport Plant Unit 1	97,957	114,918
Nuclear Fuel Disposal Costs	36,097	43,615
Other	35,451	44,164
Total Deferred Charges	339,379	379,664
Total	$3,573,847	$3,599,669

See Notes to Consolidated Financial Statements.

	December 31, 1991	December 31, 1990
	(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	717,609	717,609
Retained Earnings	164,166	145,489
Total Common Shareowner's Equity	938,359	919,682
Cumulative Preferred Stock — Not Subject to Mandatory Redemption	197,000	197,000
Long-term Debt	1,107,209	1,072,333
Total Capitalization	2,242,568	2,189,015
OTHER NONCURRENT LIABILITIES	220,998	225,652
CURRENT LIABILITIES:		
Long-term Debt Due Within One Year	13,500	51,500
Short-term Debt	43,900	33,945
Accounts Payable:		
General	47,634	62,343
Affiliated Companies	16,380	16,831
Taxes Accrued	9,141	—
Interest Accrued	22,765	21,900
Obligations Under Capital Leases	26,597	36,399
Other	63,743	55,471
Total Current Liabilities	243,660	278,389
DEFERRED CREDITS:		
Income Taxes	416,883	442,239
Investment Tax Credits	203,397	212,913
Gain on Sale and Leaseback — Rockport Plant Unit 2	226,965	234,303
Other	19,376	17,158
Total Deferred Credits	866,621	906,613
COMMITMENTS AND CONTINGENCIES (Note 3)		
Total	$3,573,847	$3,599,669

Consolidated Statements of Cash Flows

	Year Ended December 31,		
	1991	1990	1989
		(in thousands)	
OPERATING ACTIVITIES:			
Net Income	**$ 135,286**	$ 116,315	$ 137,145
Adjustments for Noncash Items:			
Depreciation and Amortization	**139,660**	138,747	133,551
Amortization of Rockport Plant Unit 1 Phase-in Costs	**16,961**	16,961	16,961
Amortization of Deferred Nuclear Fuel Disposal Costs	**7,518**	4,207	3,204
Deferred Income Taxes	**(21,821)**	(8,804)	(196,977)
Deferred State Taxes — Rockport Plant Unit 2 Sale and Leaseback Transaction	**3,558**	1,937	(39,943)
Deferred Investment Tax Credits	**(9,011)**	(8,248)	27,445
Allowance for Equity Funds Used During Construction	**(966)**	(1,174)	(27,972)
Changes in Certain Current Assets and Liabilities:			
Accounts Receivable (net)	**(4,415)**	25,688	(79,755)
Fuel, Materials and Supplies	**(14,414)**	(20,737)	4,682
Accrued Utility Revenues	**2,901**	(3,200)	(8,373)
Accounts Payable	**(15,160)**	(9,239)	18,367
Taxes Accrued	**9,141**	(200,787)	196,502
Interest Accrued	**865**	(14,201)	(252)
Other (net)	**(5,420)**	(6,919)	26,510
Net Cash Flows From Operating Activities	**244,683**	30,546	211,095
INVESTING ACTIVITIES:			
Construction Expenditures	**(119,368)**	(104,494)	(196,824)
Allowance for Equity Funds Used During Construction	**966**	1,174	27,972
Cash Used for Construction Expenditures	**(118,402)**	(103,320)	(168,852)
Proceeds from Sale and Leaseback — Rockport Plant Unit 2	**—**	—	850,000
Proceeds from Sales of Other Property	**3,246**	6,039	1,381
Net Cash Flows From (Used For) Investing Activities	**(115,156)**	(97,281)	682,529
FINANCING ACTIVITIES:			
Capital Contributions Returned to Parent	**—**	—	(63,000)
Issuance of Long-term Debt	**78,634**	40,000	—
Change in Short-term Debt (net)	**9,955**	33,945	(35,850)
Retirement of Cumulative Preferred Stock	**—**	(19,048)	(7,000)
Retirement of Long-term Debt	**(92,623)**	(451,770)	(62,512)
Dividends Paid on Common Stock	**(101,192)**	(113,064)	(119,952)
Dividends Paid on Cumulative Preferred Stock	**(15,417)**	(16,094)	(18,248)
Net Cash Flows Used For Financing Activities	**(120,643)**	(526,031)	(306,562)
Net Increase (Decrease) in Cash and Cash Equivalents	**8,884**	(592,766)	587,062
Cash and Cash Equivalents January 1	**2,721**	595,487	8,425
Cash and Cash Equivalents December 31	**$ 11,605**	$ 2,721	$ 595,487

See Notes to Consolidated Financial Statements.

Consolidated Statements of Retained Earnings

	Year Ended December 31,		
	1991	1990	1989
		(in thousands)	
Retained Earnings January 1	**$145,489**	$157,825	$161,443
Net Income	**135,286**	116,315	137,145
	280,775	274,140	298,588
Cash Dividends Declared:			
Common Stock	**101,192**	113,064	119,952
Cumulative Preferred Stock:			
4⅛% Series	**495**	495	495
4.56% Series	**273**	273	273
4.12% Series	**165**	165	165
7.08% Series	**2,124**	2,124	2,124
7.76% Series	**2,716**	2,716	2,716
8.68% Series	**2,604**	2,604	2,604
12% Series	**—**	48	838
$2.15 Series	**3,440**	3,440	3,440
$2.25 Series	**3,600**	3,600	3,600
$2.75 Series	**—**	122	1,793
Total Dividends	**116,609**	128,651	138,000
Net Premium on Reacquisition of Preferred Stock	**—**	—	2,763
Total Deductions	**116,609**	128,651	140,763
Retained Earnings December 31	**$164,166**	$145,489	$157,825

See Notes to Consolidated Financial Statements.

1. Significant Accounting Policies:

Organization and Regulation

Indiana Michigan Power Company (the Company) is a wholly owned subsidiary of American Electric Power Company, Inc. (AEP). The Company is engaged in the generation, purchase, transmission and distribution of electric power and is a member of the AEP System. Accordingly, the Company's facilities are operated in conjunction with the facilities of other AEP owned utilities as an integrated utility system.

The Company, as a subsidiary of AEP which is an electric utility holding company, is subject to the regulation of the Securities and Exchange Commission (SEC) under the Public Utility Holding Company Act of 1935 (1935 Act). The rates of the Company are regulated by the Indiana Utility Regulatory Commission (IURC), Michigan Public Service Commission (MPSC) and Federal Energy Regulatory Commission (FERC).

Principles of Consolidation

The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries. Significant intercompany transactions have been eliminated in consolidation.

Basis of Accounting

The accounting of the Company conforms to the Uniform System of Accounts prescribed by the FERC and the requirements of the state commissions. The Company also is subject to the accounting and reporting requirements of the SEC. The financial statements comply with generally accepted accounting principles.

Electric Utility Plant; Depreciation and Amortization; Other Property and Investments

Electric utility plant, which is stated at original cost, generally is subject to first mortgage liens.

The Company capitalizes, as a construction cost, an allowance for funds used during construction (AFUDC), a non-cash income item, which is defined in the applicable regulatory systems of accounts as the net cost of borrowed funds used for construction purposes and a reasonable return on equity funds when so used. The composite AFUDC rates used by the Company after compounding on a semi-annual basis were 9.25% in 1991 and 10.5% in 1990 and 1989.

The Company provides for depreciation on a straight-line basis over the estimated useful lives of its property and determines depreciation provisions largely through the use of composite rates by functional class of property.

The Company recovers through depreciation charges included in rates amounts to be used for demolition of non-nuclear plant. Decommissioning costs for the Company's nuclear plant are discussed in Note 3. Periodic demolition studies are performed in order to evaluate the amounts being collected and seek recovery of revised amounts as necessary.

Operating expenses are charged with the costs of labor, materials, supervision and other costs incurred in operating and maintaining the Company's properties. Property accounts are charged with the cost of property additions, major replacements of property and betterments. The accumulated provisions for depreciation are charged with retirements and associated removal costs net of salvage.

Other property and investments are generally stated at cost.

Cash and Cash Equivalents

The Company and its subsidiaries consider cash, unrestricted special deposits, working funds, and temporary cash investments as defined by the FERC to be cash and cash equivalents. Temporary cash investments include highly liquid investments purchased with an original maturity of three months or less.

Income Taxes

Deferred income taxes are provided except where flow-through accounting for certain timing differences is reflected in the Company's rates. The Company defers and amortizes over the life of its plant the effect of tax reductions resulting from investment tax credits utilized in Federal income tax returns consistent with rate-making policies.

Operating Revenues

The Company accrues revenues for electric service rendered but unbilled at month-end.

Fuel Costs

The Company bills its fuel costs under fuel recovery mechanisms designed to reflect, in rates, changes in costs of fuel with the approval of various regulatory commissions. Accordingly, the Company accrues revenues related to unrecovered fuel.

Other

In accordance with regulatory approvals, the Company recognizes gain or loss on reacquired debt in income in the year of reacquisition unless such debt is refinanced, in which case, the gain or loss is deferred and amortized over the term of the replacement debt.

Debt discount or premium and debt issuance expenses are being amortized over the lives of the related debt issues, and the amortization thereof is included in other interest charges.

The excess of par value over costs of cumulative preferred stock reacquired to meet sinking fund requirements is credited to paid-in capital. Redemption premiums paid by the Company are deferred and amortized in accordance with ratemaking treatment.

Reclassifications

The Company changed the way it reports interchange power transactions in accordance with an accounting release of the FERC. The accounting release requires that interchange power transactions which involve delivery of energy to the AEP System Power Pool or to unaffiliated utilities for settlement in cash be recorded as revenues instead of as credits to the purchased and interchange power expense account. This change increased revenues on a restated basis by $231 million in 1990 and $116 million in 1989 with a corresponding increase in purchased and interchange power expense. There was no effect on net income.

In addition certain other prior-period amounts have been reclassified to conform to current-period presentation.

2. Rate Matters:

Rate Recovery

During 1991 the IURC issued orders on rehearing granting the Company additional annual revenues of approximately $4 million. These orders stem from a rate proceeding that began in July 1989 when the Company requested an annual increase in rates of $60 million. In 1990 the IURC granted the Company an increase in rates of $19 million annually.

In February 1991 the MPSC approved a settlement agreement granting the Company a two step increase of $7.4 million in April 1991 and $3 million in April 1992. The settlement agreement resulted from a request filed in June 1990 seeking an annual increase in Michigan retail rates of $16 million.

In June 1991 the FERC approved a final settlement agreement granting the Company a $4 million annual wholesale rate increase. The settlement agreement resulted from a request filed in March 1990 seeking an $11 million annual rate increase.

In November 1991 the Company filed notice with the IURC of its intent to file for a rate increase in 1992.

Coal and Transportation Charges

A FERC administrative law judge issued an initial decision in 1990 regarding a complaint filed by a wholesale customer concerning the reasonableness of the Company's coal costs and the coal transportation charges of affiliates. The initial decision would require the Company to refund to wholesale customers $25 million related to coal costs and a yet to be determined amount for affiliated transportation charges. The Company has filed exceptions to the initial decision and the matter is subject to final decision of the full Commission.

Rockport 1 Phase-in Plan

The Company is in the sixth year of phase-in plans in its Indiana and FERC jurisdictions for recovery of a portion of the cost of operation incurred in the first three years of operation of its Rockport Plant Unit 1. The phase-in plans satisfy the requirements of Statement of Financial Accounting Standards 92. At December 31, 1991 and 1990 the Company's balance sheet contained unamortized deferred returns of $76 million and $89 million, respectively, and unamortized deferred depreciation of $22 million and $26 million, respectively. The phase-in plan deferrals are being amortized on a straight-line basis through 1997.

Merger

During 1991 the Company and Michigan Power Company (MPCo), an affiliate, filed applications with the IURC, MPSC, SEC and FERC seeking approval in connection with the merger of MPCo into the Company with the surviving entity (the Company) to have all the rights, privileges and obligations of both companies prior to the merger. All applicable regulatory authorities approved the merger which became effective February 29, 1992. The merger will be accounted for as a pooling-of-interests. For the year ended December 31, 1991, operating revenues, net income and earnings applicable to common stock would have been $1,226 million, $137 million and $122 million, respectively, if the merger had occurred in 1991. The merger will not significantly impact results of operations or financial condition.

3. Commitments and Contingencies:

Construction

The construction expenditures of the Company and its subsidiaries for the years 1992-1994 are estimated at $438 million, exclusive of the requirements of the Clean Air Act Amendments of 1990 and, in connection with the construction program, commitments have been made.

Unit Power Agreements

The Company is committed under unit power agreements to purchase from AEP Generating Company (AEGCo), an affiliated company, 70% of AEGCo's Rockport Plant capacity unless it is sold to unaffiliated utilities.

Fuel Supply

The Company has long-term contracts to obtain fuel for electric generation. The contracts generally contain clauses that provide for periodic price adjustments and the Company's jurisdictions have fuel clause mechanisms that generally provide for recovery of changes in the cost of fuel. The contracts are for as long as 23 years and contain clauses that would release the Company from its obligation under certain conditions.

Litigation

In February 1990 the Supreme Court of Indiana overruled an appeals court and reversed an IURC order that had assigned a major industrial customer to the Company's service territory. In August 1990 the IURC issued an order transferring the right to serve the industrial customer to an unaffiliated local distribution utility. Concurrent with the transfer of service the Company began providing service to the local distribution utility in an amount sufficient to meet the energy needs of the industrial customer.

In October 1990 the local distribution utility sued the Company under a provision of Indiana law that allows the local distribution utility to seek damages equal to the gross revenues received by a utility that renders retail service in the designated service territory of another utility. The Company received revenues of approximately $29 million from serving the major industrial customer. It is not clear whether such a claim would be upheld since the service was rendered in accordance with an IURC order which the Company believed in good faith to be valid. The matter is pending.

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

Environmental Matters

The Company and its subsidiaries are subject to regulation by Federal, state and local authorities with respect to air- and water-quality control and other environmental matters, and are subject to zoning and other regulation by local authorities.

The generation of electricity produces non-hazardous and hazardous by-products. Also asbestos, polychlorinated biphenyls (PCB's) and other hazardous materials have been used in the Company's generating plants and transmission/distribution facilities. The Company incurs substantial costs to store and dispose of hazardous materials in accordance with current laws and regulations. Significant additional costs could be incurred to meet the requirements of new laws and regulations.

The Clean Air Act Amendments of 1990 require, among other things, significant reductions in the emission of sulfur dioxide and nitrogen oxide from various existing AEP System generating plants. The law established a deadline of 1995 for the first phase of reductions and 2000 for the second phase as well as a permanent nationwide cap on sulfur dioxide emissions after 1999. The AEP System reviewed the provisions of the 1990 law and is evaluating compliance alternatives which include: (a) installation of sulfur dioxide and nitrogen oxide emissions reduction equipment on affected generating units which would require substantial capital expenditures and result in significant operating costs and reduced generating efficiency; (b) switching to lower sulfur coal or natural gas, resulting in adverse impacts on affiliated mining operations and related facilities and less substantial capital expenditures; and (c) premature retirement of certain generating units.

The AEP System has completed a preliminary systemwide compliance report (Compliance Report) as ordered by a state commission in an affiliate's retail jurisdiction. The Compliance Report evaluated the cost of compliance with the Clean Air Act Amendments on a systemwide basis and compared preliminary estimates of the revenue requirements on a five-year average, a 10-year average and a 16-year net present value basis. The Company's additional annual revenue requirement for the System's least cost option, excluding any potential transfer payments or credits for emission allowances, is estimated to be $15 million based on a five-year average and $29 million based on a 10-year average. The 10-year average includes tentatively projected Phase II compliance measures which expanded the compliance requirements to additional generating units and increased the cost. Unless the costs of compliance are recovered through rates, the Company's results of operations will be adversely affected.

Recent concerns about the potential for global climate change and policies to address this issue continue to be the focus of international negotiations and Congressional debate. Legislation has been introduced in Congress to control emission of "greenhouse" gases such as carbon dioxide. Since the System's coal-fired generating plants emit significant

quantities of carbon dioxide, the cost of any restrictions could adversely affect the Company's results of operations and financial position if not recovered from ratepayers.

Nuclear Insurance

The Price-Anderson Act limits the public liability of a licensee of a nuclear plant for a nuclear incident to $7.7 billion. The Company maintains the maximum private insurance available of $200 million for the Donald C. Cook Nuclear Plant (Cook Plant). The balance of any claims would be paid by a retrospective deferred premium assessment plan. The maximum standard deferred premium that the Company may be assessed, in the event of a nuclear incident at any nuclear plant, is $63 million per reactor, but may not exceed $10 million in any one year. If claims exceed the amount of liability insurance and deferred premiums, a licensee must pay a surcharge of up to 5 percent of the standard deferred premium for such claims. Thus, if damages in excess of private insurance result from a nuclear incident, the Company could be assessed its pro rata share of the liability up to a maximum of $126 million for its two reactors, in annual installments of $20 million plus $6.3 million for excess claims. There is no limit on the number of incidents for which the Company could be assessed these sums.

The Company also has property damage, decontamination and decommissioning insurance in the amount of $2.515 billion. Nuclear insurance pools provide $1.265 billion of coverage and Nuclear Electric Insurance Limited (NEIL) provides the remainder. If NEIL's losses exceed its available resources, the Company would be subject to a retrospective premium assessment of up to $7.4 million. Nuclear Regulatory Commission regulations require that the insurance proceeds must be used, first, to return the reactor to, and maintain it in, a safe and stable condition and, second, to decontaminate the reactor and reactor station site. The insurers then would indemnify the Company for property damage up to $2.315 billion less any amounts used for stabilization and decontamination. As provided by NEIL the remaining $200 million (less any stabilization and decontamination expenditures over $2.315 billion) would cover decommissioning costs in excess of funds already collected for decommissioning, as discussed below.

NEIL's extra-expense program provides insurance to cover extra costs from a prolonged accidental outage of a nuclear unit. The Company's policy insures against such increased costs up to approximately $3.5 million per week (starting 21 weeks after the outage) for the first year, $2.3 million per week for the second year and $1.15 million per week for the third year, or 80% of those amounts per unit if both units are down for the same reason. If NEIL's losses exceed its available resources, the Company would be subject to a retrospective premium assessment of up to $9 million.

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including liabilities relating to damage to the Cook Plant and other costs in the event of a nuclear incident at the Cook Plant. Any future losses or liabilities which are not completely insured, unless recovered through rates, could have a material adverse effect on results of operations and financial condition of the Company.

Disposal of Spent Nuclear Fuel and Nuclear Decommissioning

The Nuclear Waste Policy Act of 1982 established Federal responsibility for the permanent off-site disposal of spent nuclear fuel and assesses owners of nuclear plants fees for the disposal cost. The Company entered into a contract with the U.S. Department of Energy (DOE) for the disposal of spent nuclear fuel. Under the terms of the contract the Company pays a fee of one mill per kwh sold for fuel consumed after April 6, 1983 which is being collected from customers and remitted to the U.S. Treasury. The fee for disposal of fuel consumed prior to April 7, 1983 of $72 million plus interest of $66 million to December 31, 1991, has been recorded as other long-term debt and deferred. The amount deferred is being amortized commensurate with recovery from ratepayers. Due to the delays and continuing uncertainties of DOE's program for permanent disposal of spent nuclear fuel, the Company has not commenced paying the fee for fuel consumed prior to April 7, 1983. Funds collected from ratepayers of $10 million in each year for 1991, 1990 and 1989 were deposited in external funds. Interest earned by the external funds, $6 million in 1991, $3 million in 1990 and $4 million in 1989, increase the fund balance and will be used to settle the Company's liability for disposal of nuclear fuel consumed prior to April 7, 1983.

The Company has received regulatory approval from all of its jurisdictions to recover an approved level of decommissioning costs in revenues which before income taxes amounted to $11 million in 1991, $10 million in 1990 and $9 million in 1989. These collections were granted by the Company's regulatory commissions after the commissions reviewed a study by an independent consulting firm employed by the Company, which estimated that the cost of decommissioning the Cook Plant could range from $330 million to $369 million in 1989 dollars.

The consultant recently updated this study, which has not yet been filed with or reviewed by the Company's regulators. The update estimates, based on changed conditions (related to delays in DOE's program for disposal of spent nuclear fuel and other factors), that the cost of post-shutdown fuel storage and decommissioning at the Cook Plant would be in the range of $588 million to $1,102 million in 1991 dollars for the cases studied. The substantial increase is primarily due to the possible need to store spent nuclear fuel at the plant site for an extended time after the plant ceases operation delaying the commencement of dismantling activities. Variables in the length of time spent nuclear fuel must be stored at the plant subsequent to ceasing operations, which is dependent on future developments in DOE's program for disposal of spent nuclear fuel, have widened the range of the estimate. The Company intends to seek an appropriate increase in its level of collections for decommissioning expense. The Company will continue to periodically reevaluate the cost of decommissioning and to seek regulatory approval to revise its rates as necessary.

The Company records decommissioning costs in other operation expense and records a provision for nuclear decommissioning expense in other noncurrent liabilities equal to the amount of cost recovery in rates. Funds recovered through the rate-making process for nuclear decommissioning are deposited in external funds for the future payment of such costs. Trust fund earnings increase the fund balance and the recorded liability, thus reducing the amount to be collected from ratepayers.

4. Common Shareowner's Equity:

In December 1989 the Company returned $63 million of cash capital contributions to its parent from paid-in capital. In 1989, the Company recorded charges of $1.2 million to paid-in capital and $2.8 million to retained earnings representing the write-off of premiums paid in connection with the reacquisition of its $3.63 Series Cumulative Preferred Stock. There were no other transactions affecting the common stock or paid-in capital accounts in 1991, 1990 or 1989.

Covenants in mortgage indentures, debenture and bank loan agreements, charter provisions and orders of regulatory authorities place various restrictions on the use of retained earnings of the Company to pay dividends (other than stock dividends) on its common stock and for other purposes. At December 31, 1991, approximately $45.9 million of retained earnings were restricted. In addition, regulatory approval is required for the Company to pay dividends out of paid-in capital.

5. Related-party Transactions:

The Company is a member of the AEP System Power Pool (Power Pool) which allows the Company to share the benefits and costs associated with the System's generating plants. Under the terms of the System Interchange 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. Net energy charges and credits are intended to compensate Power Pool members for their out of pocket cost when they deliver more energy to the Power Pool than they receive. In addition the Company shares in wholesale sales to unaffiliated utilities made by the Power Pool. The Company's share was credited to operating revenues in the amount of $65.5 million in 1991, $126.7 million in 1990 and $127.7 million in 1989.

The revenues (credits) from providing capacity and supplying energy to the Power Pool totaled $204.8 million in 1991, $230.5 million in 1990 and $114.1 million in 1989. The placing in service of the 1300 mw Rockport Plant Unit 2 in December 1989 accounted for the significant increase in Power Pool capacity credits beginning in 1990. The charges for energy received from the Power Pool were included in purchased and interchange power expense and totaled $24.6 million in 1991, $53.9 million in 1990 and $96.4 million in 1989.

The Power Pool purchases power for immediate resale to other unaffiliated utilities. The Company's share of these purchases is included in purchased and interchange power expense and totaled $13.7 million in 1991, $28.2 million in 1990 and $21.5 million in 1989.

Operating revenues shown in the Consolidated Statements of Income include sales of energy to MPCo, an affiliated utility that is not a member of the Power Pool, of approximately $32 million, $31 million and $32 million for the years ended December 31, 1991, 1990 and 1989, respectively.

The cost of power purchased from AEGCo, an affiliated company that is not a member of the Power Pool, shown as purchased and interchange power expense was $83 million, $79 million and $13 million in 1991, 1990 and 1989, respectively.

The Company participates with other AEP System companies 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, the Company recorded in other operation expenses credits of \$46.2 million, \$47.6 million and \$37.3 million for transmission services in 1991, 1990 and 1989, respectively.

The Company recorded revenues in nonoperating income from providing barging services as follows:

	Year Ended December 31,		
	1991	1990	1989
		(in thousands)	
Affiliated Companies	\$16,306	\$17,094	\$21,092
Unaffiliated Companies	4,641	2,882	5,173
Total	\$20,947	\$19,976	\$26,265

American Electric Power Service Corporation (AEPSC) provides certain professional services to the Company and its affiliated companies in the AEP System. The costs of the services are determined 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, all of which is furnished to AEPSC by AEP. The Company expenses or capitalizes billings from AEPSC depending on the nature of the professional service rendered. AEPSC and its billings are subject to the regulation of the SEC under the 1935 Act.

6. Benefit Plans:

The Company and its subsidiaries participate with other companies in the AEP System in a trusteed, noncontributory defined benefit plan to provide pensions, subject to certain eligibility requirements, for all employees. Plan benefits are determined by a formula which considers each participant's highest average earnings, years of accredited service and social security covered compensation. Pension costs are allocated to each System company 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 Company and its subsidiaries' funding policy is to make annual contributions to the plan's trust fund equal to the net periodic pension cost to the extent deductible for Federal income tax purposes, but not less than the minimum contribution required by law.

Net pension costs for the years ended December 31, 1991, 1990 and 1989 were \$2.3 million, \$2.7 million and \$1.3 million, respectively.

The Company offers an employee savings plan under which eligible participants can invest from 1% to 16% of their salaries among three investment alternatives, including AEP common stock. An employer contribution equal to one-half of the first 6% of the employees' contributions is invested in AEP common stock. The Company's annual contributions to the savings plan trust were \$3 million in 1991, \$2.8 million in 1990 and \$2.7 million in 1989.

In addition to providing pension benefits, the Company and its subsidiaries provide certain other benefits for retired employees. Substantially all employees may become eligible for health care and life insurance benefits if they have 10 years of service at retirement. The cost of retiree benefits is recognized as an expense when paid and totaled \$2.4 million in 1991, \$2.6 million in 1990 and \$2.1 million in 1989.

The Financial Accounting Standards Board (FASB) has issued Statement of Financial Accounting Standards (SFAS) 106 *Employers' Accounting for Postretirement Benefits Other Than Pensions* which requires employers, beginning in 1993, to accrue for the costs of retiree benefits other than pensions. SFAS 106 requires the recognition of prior service costs (the unfunded and unrecognized accumulated postretirement benefit obligation) in the initial year of implementation or their accrual as a transition obligation over either the greater of the average remaining service period of employees or 20 years. The Company expects to elect the 20-year transition option. In anticipation of this new requirement, the Company and its subsidiaries established a Voluntary Employee Beneficiary Association (VEBA) trust fund for postretirement benefits other than pensions and made a \$4.1 million contribution in 1990, the maximum amount deductible for Federal income tax purposes. Another measure taken by the Company in 1990, except where restricted by state law, was to implement a program of corporate owned life insurance to help fund and reduce the future cost of postretirement benefits other than pensions. The insurance policies have a substantial cash surrender value which is recorded, net of equally substantial policy loans, as other property and investments. In 1991 the policies generated \$700,000, inclusive of related tax benefits, which was contributed to the VEBA trust fund.

The pension and other postretirement benefit plans were amended effective January 1, 1992. The change in the pension plan allows employees to retire without reduction of benefits at age 62 instead of age 65 and to retire as early as age 55 instead of age 60 with reduced benefits. It is estimated that the pension plan amendments will increase annual pension expense in 1992 to $5.5 million. The change in the other postretirement benefit plan grants employees eligibility for health care and life insurance benefits if they retire as early as age 55 with 10 years of service. Previously employees could not receive other postretirement benefits unless they retired at age 60 or later.

The annual expense required by SFAS 106 for employees and retirees, inclusive of the changes in the other postretirement benefit plan, is expected to be approximately three times the currently recognized pay-as-you-go expenses and the transition obligation is estimated to range from $80 million to $90 million. The Company plans to seek recovery of the increased expense in its next base rate filing and to request authority before January 1, 1993 to defer under the provisions of SFAS 71 any increased costs for which recovery is not provided currently. Although the Company expects to file a rate case in its Indiana jurisdiction in the second quarter of 1992, the Company is unable to determine if the rate proceeding will be concluded by the January 1, 1993 effective date. Should recovery of or a commitment to allow future recovery of the SFAS 106 accruals be denied, the Company's results of operations and possibly its financial condition would be adversely impacted.

7. Supplementary Information:

The following are the components of taxes other than Federal income taxes:

	Year Ended December 31,		
	1991	1990	1989
		(in thousands)	
Real and Personal Property	$31,892	$26,946	$31,897
State Gross Receipts, Excise, Franchise and Miscellaneous State and Local	15,469	12,156	29,282
State Income	4,848	5,760	28,057
Payroll	7,914	7,590	7,084
Deferred Taxes — Rockport 2 Sale and Leaseback Transaction	926	1,937	(39,943)
Total	$61,049	$54,389	$56,377

The following are the amounts of cash paid for:

	Year Ended December 31,		
	1991	1990	1989
		(in thousands)	
Interest (net of capitalized amounts)	$83,276	$101,905	$107,124
Income Taxes	72,831	247,172	64,843

The amounts of non-cash investing acquisitions under capital leases were $25,438,000 in 1991, $57,112,000 in 1990 and $9,035,000 in 1989.

8. Federal Income Taxes:

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

	Year Ended December 31,		
	1991	1990	1989
		(in thousands)	
Charged (Credited) to Operating Expenses (net):			
Current	$ 73,010	$52,894	$ 215,793
Deferred	(18,737)	(6,921)	(196,503)
Deferred Investment Tax Credits	(8,277)	(5,759)	27,465
Total	45,996	40,214	46,755
Charged (Credited) to Nonoperating Income (net):			
Current	3,370	7,288	1,234
Deferred	(3,084)	(1,883)	(474)
Deferred Investment Tax Credits	(734)	(2,489)	(20)
Total	(448)	2,916	740
Total Federal Income Taxes as Reported	$ 45,548	$43,130	$ 47,495

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,		
	1991	1990	1989
		(in thousands)	
Net Income	$135,286	$116,315	$137,145
Federal Income Taxes	45,548	43,130	47,495
Pre-tax Book Income	$180,834	$159,445	$184,640
Federal Income Taxes on Pre-Tax Book Income at Statutory Rate (34%)	$ 61,484	$ 54,211	$ 62,778
Increase (Decrease) in Federal Income Taxes Resulting From the Following Items:			
Allowance for Funds Used During Construction	(2,071)	(2,161)	(12,364)
Mine Development and Mineral Rights Amortization	2,773	4,369	3,048
Investment Tax Credits (net)	(8,910)	(10,810)	(6,395)
Other	(7,728)	(2,479)	428
Total Federal Income Taxes as Reported	$ 45,548	$ 43,130	$ 47,495
Effective Federal Income Tax Rate	25.2%	27.1%	25.7%

The following are the principal components of Federal income taxes as reported:

	Year Ended December 31,		
	1991	1990	1989
		(in thousands)	
Current:			
Federal Income Taxes	$76,279	$62,744	$250,867
Investment Tax Credits	101	(2,562)	(33,840)
Total Current Federal Income Taxes	76,380	60,182	217,027 (a)
Deferred:			
Depreciation	(7,000)	1,041	2,254
Allowance for Borrowed Funds Used During Construction	(1,960)	(2,519)	7,433
Unrecovered and Levelized Fuel	(492)	4,214	(5,453)
Nuclear Fuel	(6,484)	384	(2,701)
Unbilled Revenue	—	(3,349)	(3,713)
Deferred Return — Rockport Plant Unit 1	(2,864)	(2,864)	(2,864)
Sale of Rockport Plant Unit 2	—	—	(56,863)
Deferred Net Gain — Rockport Plant Unit 2	3,099	3,457	(128,194)
Other	(6,120)	(9,168)	(6,876)
Total Deferred Federal Income Taxes	(21,821)	(8,804)	(196,977)
Total Deferred Investment Tax Credits	(9,011)	(8,248)	27,445 (a)
Total Federal Income Taxes as Reported	$45,548	$43,130	$ 47,495

(a) The significant increase in current Federal income taxes resulted from the gain on the sale of Rockport 2. The placing of Rockport 2 in service in December 1989 enabled the Company to utilize significant investment tax credits generated by the sale and leaseback to reduce its taxes payable. The tax effect of both the gain and the credits utilized were deferred.

The Company and its subsidiaries join in the filing of a consolidated Federal income tax return with their affiliated companies in the AEP System. The allocation of the AEP System's current consolidated Federal income tax to the System companies is in accordance with SEC rules under the 1935 Act. These rules permit the allocation of the benefit of current tax losses and investment tax credits utilized to the System companies giving rise to them in determining taxes currently payable. The tax loss of the System parent company, AEP, 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.

At December 31, 1991, the cumulative net amount of income tax timing differences on which deferred taxes have not been provided totaled $442 million.

The AEP System reached a settlement with the Internal Revenue Service (IRS) for all issues from the audits of the consolidated Federal income tax returns for the years prior to 1985. Returns for the years 1985 through 1987 are being audited by the IRS. In the opinion of management, the final settlement of open years should not have a material effect on the earnings of the Company.

The FASB has issued SFAS 109 *Accounting for Income Taxes* which supersedes SFAS 96. SFAS 109 requires the use of the liability method of accounting for income taxes and has an effective date of January 1, 1993. SFAS 109 may be adopted on a restated basis or as a cumulative effect of an accounting change in the year of adoption.

When the new standard is adopted, total assets and liabilities will increase significantly to reflect previously unrecorded deferred tax assets and liabilities on temporary differences and related regulatory assets and liabilities. In addition, existing deferred taxes will be adjusted to the level required at the then-current statutory tax rate. It is not presently anticipated that implementation of the new standard will significantly impact results of operations and financial condition. Whether the new standard will be implemented on a restated or prospective basis has not yet been determined.

9. Unaudited Quarterly Financial Information:

The following consolidated quarterly financial information is unaudited but, in the opinion of the Company, includes all adjustments (consisting of only normal recurring accruals) necessary for a fair presentation of the amounts shown:

Quarterly Periods Ended	Operating Revenues (a)	Operating Income	Net Income
		(in thousands)	
1991			
March 31	$304,444	$60,319	$39,793
June 30	289,630	48,437	28,460
September 30	311,214	60,679	35,311
December 31	306,319	54,875	31,722
1990			
March 31	323,320	59,281	37,699
June 30	312,350	48,733	27,442
September 30	317,823	52,886	32,077
December 31	303,596	37,236	19,097

(a) Quarterly revenues have been restated to reflect the reclassification described in Note 1.

10. Leases:

The Company and its subsidiaries lease property, plant and equipment for periods up to 35 years. Most of the leases require the lessee to pay related property taxes, maintenance costs and other costs of operation. The Company and its subsidiaries expect that leases generally will be renewed or replaced by other leases. The majority of the leases have purchase or renewal options.

The Company and AEGCo each lease 50% of Rockport 2 which cost $1.3 billion and began commercial operation in December 1989. Rockport 2 was sold in December 1989 for $1.7 billion, its estimated fair market value, and leased back for an initial term of 33 years. The gain from the sale was deferred and is being amortized, with related deferred taxes, over the initial lease term. The leases are accounted for as operating leases.

The Company leases its nuclear fuel from a special purpose entity which provides for leasing of up to $140 million of nuclear fuel. The special purpose entity owns the nuclear fuel and finances all of its investment in nuclear fuel. The Company accounts for the nuclear fuel lease as a capital lease.

Rental payments for capital and operating leases are primarily charged to operating expenses in accordance with ratemaking treatment. The components of rental payments are as follows:

	Year Ended December 31,		
	1991	1990	1989
		(In thousands)	
Operating Leases	$100,958	$ 87,357	$16,454
Capital Leases:			
Amortization of Principal	54,453	46,836	52,815
Interest	9,865	10,877	13,733
Total Rental Payments	$165,276	$145,070	$83,002

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

	December 31,	
	1991	1990
	(in thousands)	
Electric Utility Plant:		
Production	$ 10,568	$ 9,090
Distribution	14,652	14,607
General:		
Nuclear Fuel (net of amortization)	66,456	96,914
Other	38,601	38,013
Total Electric Utility Plant	130,277	158,624
Accumulated Amortization	27,970	25,675
Net Electric Utility Plant	102,307	132,949
Other Property	1,949	2,008
Accumulated Amortization	1,745	1,893
Net Other Property	204	115
Net Properties under Capital Leases	$102,511	$133,064
Obligations under Capital Leases (a)	$102,511	$133,064

(a) Including amounts due within one year.

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

Future minimum lease payments, by year and in the aggregate, consisted of the following at December 31, 1991:

	Capital Leases	Operating Leases
	(In thousands)	
1992	$ 8,000	$ 93,000
1993	6,000	92,000
1994	5,000	92,000
1995	5,000	91,000
1996	4,000	91,000
Later Years	32,000	2,099,000
Total Future Minimum Lease Payments	60,000	$2,558,000
Less Estimated Interest Element	23,000	
Estimated Present Value of Future Minimum Lease Payments	37,000	
Unamortized Nuclear Fuel	66,000 (a)	
Total	$103,000	

(a) Including portion due within one year. Rental payments for nuclear fuel will be paid in proportion to heat produced and carrying charges on the lessor's unrecovered costs. Nuclear fuel rentals of $56.6 million, $50 million and $59.2 million were charged to fuel expense in 1991, 1990 and 1989, respectively.

Included in the above analysis of future minimum lease payments and of properties under capital leases and related obligations are certain leases in which portions of the related rentals are paid for or reimbursed by affiliated companies in the AEP System based on their usage of the leased property. The Company and its subsidiaries cannot predict the extent to which affiliated companies will utilize the properties under such leases in the future.

11. Cumulative Preferred Stock:

At December 31, 1991, authorized shares of cumulative preferred stock were as follows:

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

In 1990 and 1989, the Company redeemed 47,325 and 30,000 shares, respectively, of the 12% series and 531,900 and 160,000 shares, respectively, of the $2.75 series cumulative preferred stock subject to mandatory redemption. The cumulative preferred stock is callable at the option of the Company 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. The cumulative preferred stock not subject to mandatory redemption is as follows:

Series	Call Price December 31, 1991	Par Value	Shares Outstanding December 31, 1991	Amount December 31, 1991	Amount December 31, 1990
				(in thousands)	
4⅛%	$106.125	$100	120,000	$ 12,000	$ 12,000
4.56%	102	100	60,000	6,000	6,000
4.12%	102.728	100	40,000	4,000	4,000
7.08%	101.85	100	300,000	30,000	30,000
7.76%	102.28	100	350,000	35,000	35,000
8.68%	103.10	100	300,000	30,000	30,000
$2.15	26.08	25	1,600,000	40,000	40,000
$2.25	26.13	25	1,600,000	40,000	40,000
				$197,000	$197,000

12. Long-term Debt and Lines of Credit

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

	December 31, 1991	December 31, 1990
	(in thousands)	
First Mortgage Bonds	$ 627,494	$ 599,179
Sinking Fund Debentures	6,053	6,188
Notes Payable to Banks	40,000	80,000
Installment Purchase Contracts	308,971	308,175
Other Long-term Debt (a)	138,191	130,291
	1,120,709	1,123,833
Less Portion Due Within One Year	13,500	51,500
Total	$1,107,209	$1,072,333

(a) Nuclear Fuel Disposal Costs including interest accrued. See Note 3.

First mortgage bonds outstanding were as follows:

% Rate	Due	December 31, 1991	December 31, 1990
		(in thousands)	
4⅝	1993 — August 1	$ 42,902	$ 42,902
7⅞	1997 — February 1	50,000	50,000
9⅛	1997 — July 1	75,000	75,000
7	1998 — May 1	35,000	35,000
8⅞	2000 — April 1	50,000	50,000
9½	2003 — June 1 (a)	162,000	173,500
8⅜	2003 — December 1	40,000	40,000
9½	2008 — March 1	34,034	34,034
8¾	2017 — February 1	100,000	100,000
9.5	2021 — May 1	10,000	—
9.5	2021 — May 1	10,000	—
9.5	2021 — May 1	20,000	—
Unamortized Discount (net)		(1,442)	(1,257)
		627,494	599,179
Less Portion Due Within One Year		13,500	11,500
Total		$613,994	$587,679

(a) The 9½% series due 2003 requires sinking fund payments of $13,500,000 annually on June 1, 1992 through 2002 with the noncumulative option to redeem an additional amount in each of the specified years from a minimum of $100,000 to a maximum equal to the scheduled requirement for each year, but with a maximum optional redemption, as to all years in the aggregate, of $75,000,000.

The 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.

The sinking fund debentures are due May 1, 1998 at an interest rate of 7¼%. Prior to December 31, 1991 sufficient principal amounts of debentures had been reacquired in anticipation of all future sinking fund requirements. The Company may call additional debentures of up to $300,000 annually.

Unsecured promissory notes payable to banks have been entered into by the Company as follows:

	December 31, 1991	December 31, 1990
	(in thousands)	
9.28% due 1991	$ —	$20,000
9.28% due 1991	—	20,000
9.07% due 1995	40,000	40,000
Total	$40,000	$80,000

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

% Rate	Due	December 31, 1991	December 31, 1990
		(in thousands)	
City of Lawrenceburg, Indiana:			
8½	2006 — July 1	$ 25,000	$ 25,000
7	2006 — May 1	40,000	40,000
6⅞	2006 — May 1	12,000	12,000
City of Rockport, Indiana:			
9⅛	2005 — June 1	—	6,500
9¼	2010 — June 1	—	33,500
9¼	2014 — August 1	50,000	50,000
6¾ (a)	2014 — August 1	50,000	50,000
(b)	2014 — August 1	50,000	50,000
7.6	2016 — March 1	40,000	—
City of Sullivan, Indiana:			
7⅜	2004 — May 1	7,000	7,000
6⅞	2006 — May 1	25,000	25,000
7½	2009 — May 1	13,000	13,000
Unamortized Discount		(3,029)	(3,825)
Total		$308,971	$308,175

(a) The adjustable interest rate changed on August 1, 1990 and will change every five years thereafter.

(b) The variable interest rate is determined weekly. The average weighted interest was 4.7% for 1991 and 6.5% for 1990.

Under the terms of certain installment purchase contracts, the Company is required to pay purchase price installments in 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 Company's share of construction of pollution control facilities at certain generating plants of the Company. On certain series the principal is payable at stated maturities or on the demand of the bondholders at periodic interest adjustment dates. Accordingly, the installment purchase contracts have been classified for repayment purposes based on their next interest rate adjustment date. Certain series are supported by bank letters of credit which expire in 1995.

Long-term debt, excluding premium or discount, outstanding at December 31, 1991 is due as follows:

	Principal Amount
	(in thousands)
1992	$ 13,500
1993	56,402
1994	13,500
1995	153,500
1996	13,500
Later Years	874,778
Total	$1,125,180

The amount of short-term debt the Company may borrow is limited by the provisions of the 1935 Act to $200 million and further limited by provision of the charter to $130 million The Company shares bank lines of credit with other AEP System companies and at December 31, 1991 and 1990 had unused shared lines of $374 million and $263 million, respectively. Under the terms of the lines of credit, notes can be issued with a maturity of up to 270 days. In accordance with agreements with the banks, commitment fees averaging approximately 3/16 of 1% a year are required to maintain the lines of credit.

Operating Statistics

	1991	1990	1989	1988	1987
Operating Revenues (in thousands):					
From Kilowatt-hour Sales:					
Retail:					
Residential:					
Without Electric Heating	**$ 192,926**	$ 179,955	$ 182,786	$ 189,845	$ 186,418
With Electric Heating	**90,495**	86,108	93,291	96,145	90,261
Total Residential	**283,421**	266,063	276,077	285,990	276,679
Commercial	**206,243**	195,184	196,404	194,982	191,352
Industrial	**226,085**	228,927	233,990	233,855	235,470
Miscellaneous	**11,631**	11,273	11,475	11,645	11,533
Total Retail	**727,380**	701,447	717,946	726,472	715,034
Wholesale (sales for resale)	**464,527**	545,556	390,685	319,211	354,441
Total from Kilowatt-hour Sales	**1,191,907**	1,247,003	1,108,631	1,045,683	1,069,475
Provision for Revenue Refunds	**5,175**	(5,175)	—	(1,800)	—
Total Net of Provision for Revenue Refunds	**1,197,082**	1,241,828	1,108,631	1,043,883	1,069,475
Other Operating Revenues	**14,525**	15,261	12,776	10,111	8,855
Total Operating Revenues	**$1,211,607**	$1,257,089	$1,121,407	$1,053,994	$1,078,330

	1991	1990	1989	1988	1987
Sources and Sales of Energy (in millions of kilowatt-hours):					
Sources:					
Net Generated:					
Fossil Fuel	**12,109**	14,451	10,634	8,707	6,662
Nuclear Fuel	**15,524**	11,115	12,094	9,791	10,060
Hydroelectric	**99**	116	97	70	62
Total Net Generated	**27,732**	25,682	22,825	18,568	16,784
Purchased and Interchange (net)	**5,237**	7,983	7,630	6,341	7,912
Total Sources	**32,969**	33,665	30,455	24,909	24,696
Less: Losses, Company Use, Etc.	**1,408**	1,590	1,606	1,630	1,456
Net Sources	**31,561**	32,075	28,849	23,279	23,240
Sales:					
Retail:					
Residential:					
Without Electric Heating	**2,977**	2,774	2,792	2,825	2,719
With Electric Heating	**1,582**	1,484	1,585	1,571	1,445
Total Residential	**4,559**	4,258	4,377	4,396	4,164
Commercial	**3,575**	3,388	3,375	3,290	3,142
Industrial	**5,078**	5,140	5,168	5,036	4,834
Miscellaneous	**226**	221	228	228	221
Total Retail	**13,438**	13,007	13,148	12,950	12,361
Wholesale (sales for resale)	**18,123**	19,068	15,701	10,329	10,879
Total Sales	**31,561**	32,075	28,849	23,279	23,240

OPERATING STATISTICS (Concluded)

	1991	1990	1989	1988	1987
AVERAGE COST OF FUEL CONSUMED (in cents):					
Per Million Btu:					
Coal	**141**	145	164	182	190
Nuclear	**48**	58	61	70	75
Overall	**84**	105	106	120	117
Per Kilowatt-hour Generated:					
Coal	**1.39**	1.42	1.62	1.81	1.87
Nuclear	**.53**	.64	.67	.77	.84
Overall	**.91**	1.08	1.11	1.26	1.25
RESIDENTIAL SERVICE — AVERAGES:					
Annual Kwh Use per Customer:					
Total	**10,678**	10,047	10,434	10,596	10,146
With Electric Heating	**17,809**	16,979	18,447	18,551	17,341
Annual Electric Bill:					
Total	**$663.80**	$627.84	$658.08	$689.33	$674.13
With Electric Heating	**$1,018.93**	$985.16	$1,085.56	$1,135.46	$1,083.10
Price per Kwh (in cents):					
Total	**6.22**	6.25	6.31	6.51	6.64
With Electric Heating	**5.72**	5.80	5.88	6.12	6.25
NUMBER OF CUSTOMERS:					
Year-End:					
Retail:					
Residential:					
Without Electric Heating	**339,448**	338,171	335,625	332,488	328,937
With Electric Heating	**89,620**	88,258	87,016	85,635	84,442
Total Residential	**429,068**	426,429	422,641	418,123	413,379
Commercial	**47,433**	47,020	46,176	45,249	44,207
Industrial	**4,517**	4,494	4,485	4,479	4,345
Miscellaneous	**2,059**	2,018	2,026	1,984	1,946
Total Retail	**483,077**	479,961	475,328	469,835	463,877
Wholesale (sales for resale)	**52**	54	50	108	105
Total Customers	**483,129**	480,015	475,378	469,943	463,982

Dividends and Price Ranges of Cumulative Preferred Stock

By Quarters (1991 and 1990)

	1991 — Quarters				1990 — Quarters			
	1st	2nd	3rd	4th	1st	2nd	3rd	4th
Cumulative Preferred Stock								
($100 Par Value)								
4⅛% 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								
(MSE) — High	39	36	—	—	—	—	—	—
— Low	39	36	—	—	—	—	—	—
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/low)	—	—	—	—	—	—	—	—
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)	—	—	—	—	—	—	44/44	—
Bid (high/low)	42/39½	42/39½	42¼/39½	44/39½	—	42½/41½	42/40½	42/39½
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	80⅞	79¾	83	85¼	78	75	77	75
— Low	71	76¼	76¼	81	73	72	73	72
7.76% Series								
Dividends Paid Per Share	$1.94	$1.94	$1.94	$1.94	$1.94	$1.94	$1.94	$1.94
Market Price — $ Per Share								
(NYSE) — High	92	87⅜	87	92¾	83	79	81	83
— Low	83	83¾	83¼	88	76½	77¼	76½	76¾
8.68% Series								
Dividends Paid Per Share	$2.17	$2.17	$2.17	$2.17	$2.17	$2.17	$2.17	$2.17
Market Price — $ Per Share								
(NYSE) — High	94⅜	95	96½	100½	88½	87¼	88¾	91
— Low	89	92½	91½	95	85½	85⅛	85¼	84¾
12% Series (a)								
Dividends Paid Per Share					$1.00			
Market Price — $ Per Share								
(NYSE) — High					107½			
— Low					105¾			
($25 Par Value)								
$2.15 Series								
Dividends Paid Per Share	$0.5375	$0.5375	$0.5375	$0.5375	$0.5375	$0.5375	$0.5375	$0.5375
Market Price — $ Per Share								
(NYSE) — High	25	25⅜	25⅜	26	23⅜	22⅞	23¼	24⅜
— Low	23⅛	23½	23½	24½	21⅝	21⅜	21¾	22½
$2.25 Series								
Dividends Paid Per Share	$0.5625	$0.5625	$0.5625	$0.5625	$0.5625	$0.5625	$0.5625	$0.5625
Market Price — $ Per Share								
(NYSE) — High	26	25⅞	26	26¾	24⅜	23⅞	23½	24⅜
— Low	23⅝	24½	24¼	24	22⅞	22½	22⅝	23⅜
$2.75 Series (a)								
Dividends Paid Per Share					$0.229			
Market Price — $ Per Share								
(NYSE) — High					27			
— Low					26¾			

MSE — Midwest 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 indicates quotation not available.

(a) Redeemed February 1990.

The Company's Annual Report
(Form 10-K) to the Securities and
Exchange Commission will be available
in April 1992 to shareowners
upon written request and at no cost.
Please address such requests to:

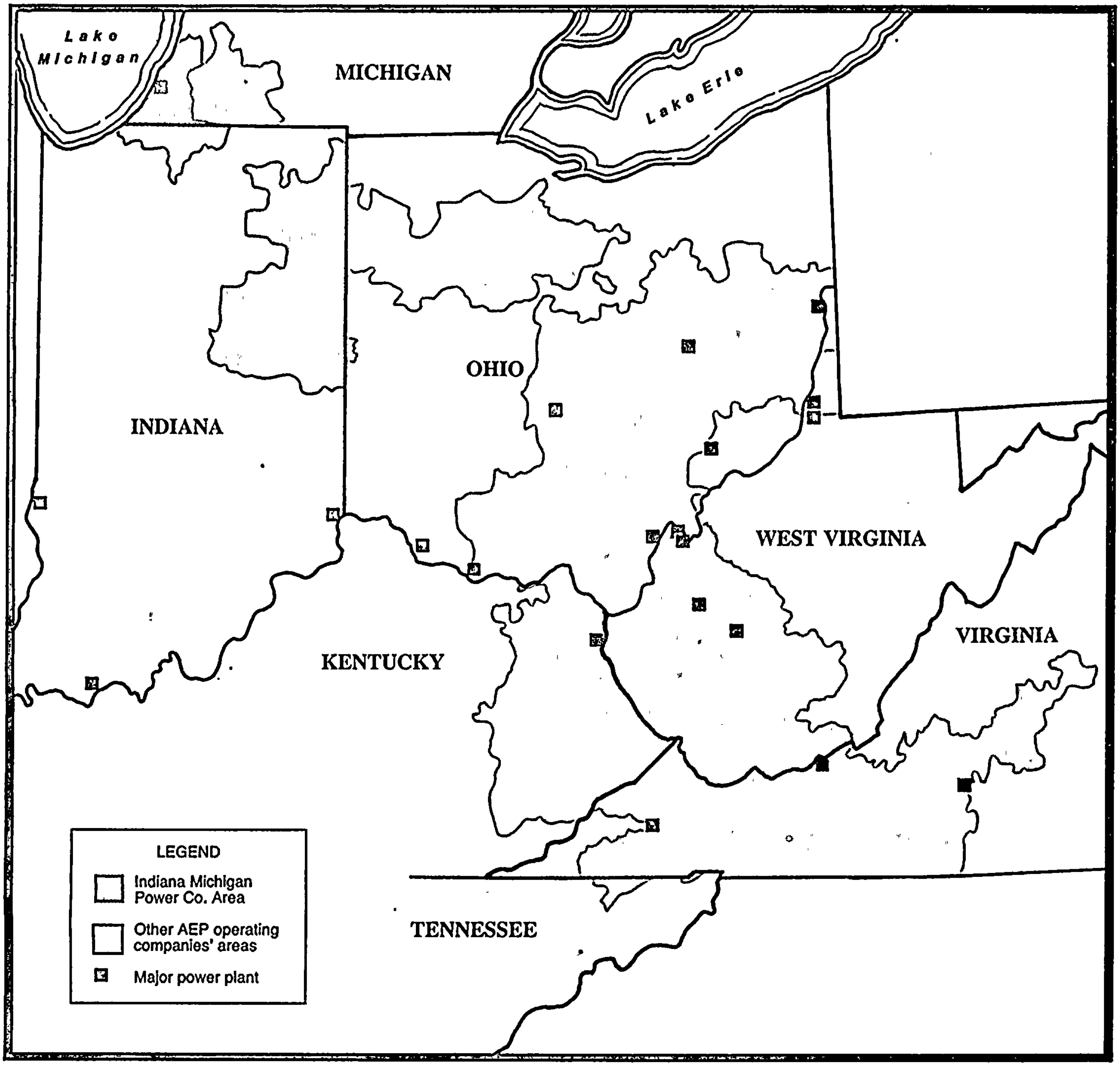
Mr. G. C. Dean
American Electric Power
Service Corporation
1 Riverside Plaza
Columbus, Ohio 43215

Transfer Agent and Registrar of Cumulative Preferred Stock

First Chicago Trust Company of New York

30 West Broadway, New York, N.Y. 10007-2192

Indiana Michigan Power Service Area and the American Electric Power System



ENCLOSURE 2 TO AEP:NRC:0909H

INDIANA MICHIGAN POWER COMPANY'S

PROJECTED CASH FLOW

1992 Internal Cash Flow Projection for Donald C. Cook Nuclear Plant

($ Millions)

	Actual 1991 (1)	Projected 1992
Net Income After Taxes	136.9	119.3
Less Dividends Paid	118.1	125.3
Retained Earnings	18.8	(6.0)
Adjustments:		
Depreciation And Amortization	158.8	160.8
Deferred Federal Income Taxes and Investment Tax Credits	(31.1)	(17.6)
AFUDC	(2.1)	(5.1)
Total Adjustments	125.6	138.1
Internal Cash Flow	144.4	132.1
Average Quarterly Cash Flow	36.1	33.0
Average Cash Balances and Short-Term Investments	5.8	11.4
Total	41.9	44.4

(1) Restated for MPCO merger with I&M

% Ownership in all operating nuclear units: Unit 1 and Unit 2 - 100%

Maximum Total Contingent Liability - $20.0 million (2 units)