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FITZPATRICK,E. Indiana Michigan Power Co. (formerly Indiana & Michigan Ele
RECIP.NAME RECIPIENT AFFILIATION
MURLEY,T.E. Office of Nuclear Reactor Regulation, Director (Post 870411

SUBJECT: Forwards "Indiana Michigan Power Co 1990 Annual Rept" & projected cash flow statement for 1991.

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AEP
INDIANA
MICHIGAN
POWER

AEP:NRC:0909G
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 9, 1991

Dear Dr. Murley:

Enclosure 1 contains the Indiana Michigan Power Company's (I&M) annual report for 1990. Enclosure 2 contains a copy of I&M's projected cash flow for 1991. 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

ldp
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

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Indiana Michigan Power Company

1990 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 480,000 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, 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).

Directors

MARK A. BAILEY
RICHARD E. DISBROW
WILLIAM N. D'ONOFRIO
ALLEN R. GLASSBURN (a)
M. RICHARD HARRELL (b)
WILLIAM J. LHOTA
GERALD P. MALONEY
RICHARD C. MENGE
DWIGHT I. PITTENGER (a)
RONALD E. PRATER (b)
DALE M. TRENARY (a)
WILLIAM E. WALTERS (b)
W. S. WHITE, JR.
DAVID H. WILLIAMS, JR.

Officers

W. S. WHITE, JR. (c)
Chairman of the Board

RICHARD E. DISBROW (d)
Vice Chairman and Chief Executive Officer

RICHARD C. MENGE
President and Chief Operating Officer

MILTON P. ALEXICH
Vice President

MARK A. BAILEY
Vice President

WILLIAM N. D'ONOFRIO
Vice President

A. JOSEPH DOWD
Vice President

RICHARD F. HERING
Vice President

WILLIAM J. LHOTA
Vice President

GERALD P. MALONEY
Vice President

DAVID H. WILLIAMS, JR.
Vice President

PETER J. DEMARIA
Treasurer

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, 1991 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, Glassburn, Menge, Moos, Pittenger, and Trenary, who were employees of Indiana Michigan Power Company.

(a) Elected April 24, 1990
(b) Resigned April 24, 1990
(c) Resigned as Chief Executive Officer January 1, 1991
(d) Elected January 1, 1991

Selected Consolidated Financial Data

	Year Ended December 31,				
	1990	1989	1988	1987	1986
			(in thousands)		
INCOME STATEMENTS DATA:					
Operating Revenues — Electric	**$1,031,059**	$1,005,638	$983,066	$1,017,268	$1,091,295
Operating Expenses	**829,626**	795,242	767,623	794,222	900,151
Operating Income	**201,433**	210,396	215,443	223,046	191,144
Nonoperating Income	**3,946**	32,930	43,454	56,828	66,905
Income Before Interest Charges	**205,379**	243,326	258,897	279,874	258,049
Interest Charges	**89,064**	106,181	107,092	113,508	105,568
Net Income	**116,315**	137,145	151,805	166,366	152,481
Preferred Stock Dividend Requirements	**15,587**	18,048	18,848	20,955	26,256
Earnings Applicable to Common Stock	**$ 100,728**	$ 119,097	$132,957	$ 145,411	$ 126,225

	December 31,				
	1990	1989	1988	1987	1986
			(in thousands)		
BALANCE SHEETS DATA:					
Electric Utility Plant	**$4,011,464**	$3,918,616	$4,411,271	$4,153,281	$3,979,822
Accumulated Depreciation and Amortization	**1,403,871**	1,292,430	1,218,060	1,118,254	1,018,455
Net Electric Utility Plant	**$2,607,593**	$2,626,186	$3,193,211	$3,035,027	$2,961,367
Total Assets	**$3,635,435**	$4,259,826	$3,993,046	$3,956,563	$3,849,208
Common Stock and Paid-in Capital	**$ 774,193**	$ 774,193	$ 838,347	$ 828,347	$ 828,347
Retained Earnings	**145,489**	157,825	161,443	145,302	113,123
Total Common Shareowner's Equity	**$ 919,682**	$ 932,018	$ 999,790	$ 973,649	$ 941,470
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	79,030
Total	**$ 197,000**	$ 215,030	$ 222,030	$ 229,030	$ 276,030
Long-term Debt (a)	**$1,123,833**	$1,522,736	$1,575,220	$1,591,768	$1,421,523
Obligations Under Capital Leases (a)	**$ 133,064**	$ 122,977	$ 167,920	$ 170,830	$ 187,845
Total Capitalization and Liabilities	**$3,635,435**	$4,259,826	$3,993,046	$3,956,563	$3,849,208

(a) Including portion due within one year.

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

Results of Operations

Net Income Declines

Net income decreased to $116 million in 1990 compared with $137 million in 1989. The decline in 1990 was predominantly due to a decline in nonoperating income as accruals for allowance for funds used during construction (AFUDC) ceased with commercial operation of Rockport Plant Unit 2 (Rockport 2) in December 1989 and increased operating and maintenance costs. In 1989 net income decreased $15 million from 1988 primarily from lower operating income and a decline in nonoperating income.

Outlook

The Company as part of the AEP System faces challenges in the 1990's that could adversely affect the Company's financial performance. While management believes the Company is equipped to deal with the future, uncertainties that could adversely affect the Company include the ability to obtain favorable rate-making treatment to recover from ratepayers its cost of service on a timely basis with particular attention currently to:

- The cost of new generating capacity.
- The cost of compliance with the Clean Air Act Amendments of 1990.

In addition, the Company's results could be negatively affected by factors not generally within management's control such as: the current and any future decline in economic activity, increased competition in the wholesale electric energy market and the weather. The ability of the Company as a member of the AEP System Power Pool (Power Pool) to make wholesale sales equal to or greater than the level of such sales reflected in the Company's rates, including the Power Pool's ability to sell the remaining portion of the Company's recently constructed Rockport 2 generating capacity not yet included in rates, will affect the Company's 1991 results of operations. Management will make every effort to continue marketing available capacity in the near term. In addition, management will be devoting particular attention in 1991 toward: efforts to increase rates to recover the cost of the recently added Rockport 2 capacity; reduction of growth in its cost of service; and preparation of a plan to comply with power plant emission restrictions of the recently enacted Clean Air Act Amendments.

Operating Revenues and Energy Sales Climb

Operating revenues rose $25 million in 1990 following a $23 million increase in 1989. Increases in wholesale kilowatt-hour (kwh) sales predominantly to unaffiliated utilities accounted for the revenue increase in both years.

The components of change in revenues are as follows:

(dollars in millions)	Increase (Decrease) From Previous Year 1990 Amount	1990 %	1989 Amount	1989 %
Retail:				
Price variance	$ (8.1)		$(18.5)	
Volume variance	(8.4)		10.0	
	(16.5)	(2.3)	(8.5)	(1.2)
Wholesale:				
Price variance	(9.2)		(48.1)	
Volume variance	48.6		74.7	
	39.4	14.3	26.6	10.7
Other Operating Revenues	2.5		4.5	
Total	$ 25.4	2.5	$ 22.6	2.3

The modest decrease in 1990 retail sales volume reflects the effects of unseasonably mild weather on residential sales. Industrial sales volume, which had shown steady growth for several years, began to slow in 1989 and experienced a slight decline in 1990. The negative effect on revenues of the lower kwh sales volume was compounded by a reduction in rates as lower average fuel costs were passed on to customers. It is important to note that with the past growth in electric heating and cooling load, results of operations have become increasingly sensitive to weather.

The increase in 1990 wholesale kwh sales was predominantly due to the commencement in January 1990 of a 250 megawatt (mw) long-term Rockport 2 unit power sales agreement. Short-term wholesale sales, which can fluctuate due to competition, the availability of unaffiliated generating capacity and weather patterns, declined slightly in 1990 partially offsetting the long-term sales increase. The positive effect of increased wholesale sales volume on 1990 revenues was partly offset by a lower average price per kwh reflecting price competition in the short-term sales for resale market. 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.

The Company as a member of the Power Pool participated in a long-term contract for the sale of up to 560 mw of power to an unaffiliated utility, which expired on December 31, 1990 and was not renewed. This contract contributed $16 million to the Company's revenues and $5 million to net income in 1990. The Power Pool is attempting to replace the terminated sales and recently reached an agreement to sell 100 mw under a long-term contract with an unaffiliated utility. In 1989 and 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. That customer is no longer expected to purchase large quantities of energy. In 1990 these sales contributed $34 million to the Company's revenues and $8 million to net income. The Power Pool is aggressively marketing available energy but cannot predict whether replacement sales will be made due to the competitive nature of the energy market and its dependence on factors which are not generally within the Power Pool's control. If the above terminated long-term and short-term sales are not replaced the Company's results of operations will be adversely impacted.

Operating Expenses Rise

Operating expenses increased 4% in 1990 after a 4% increase in 1989. Changes in the components of operating expenses were:

	Increase (Decrease) From Previous Year			
(dollars in millions)	1990		1989	
	Amount	%	Amount	%
Operating Expenses:				
Fuel	$ 26.8	10.7	$ 16.9	7.3
Purchased and Interchange Power (net)	(93.9)	(370.1)	(22.1)	(46.6)
Other Operation	73.5	43.0	9.3	5.8
Maintenance	30.3	29.1	14.7	16.4
Depreciation and Amortization	4.3	3.4	4.6	3.9
Amortization of Rockport Unit 1 Phase-in Costs	—	—	(1.1)	(6.2)
Taxes Other Than Federal Income Taxes	(2.0)	(3.5)	0.1	0.2
Federal Income Taxes	(4.6)	(10.0)	5.2	12.4
Total	$ 34.4		$ 27.6	

The increases in fuel expense in both years reflect higher net generation. With the commercial operation of Rockport 2 in December 1989, the Company became a net supplier to the Power Pool and as such commenced receiving Power Pool capacity credits which greatly reduced its purchased and interchange power expense in 1990. The Company was able to significantly decrease purchased and interchange power expense in 1989 due to the increased availability of its generating units.

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, other operation expense and maintenance expense increased in 1990 and 1989 due to scheduled outages of both of the Company's nuclear generating units. The units are refueled on an 18-month cycle. In the second half of 1990, both units were out of service for several months each for scheduled refueling. A substantial portion of the 1990 increase in nuclear plant maintenance was recorded in the fourth quarter. In 1989 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 and Unit 1 underwent a refueling outage. The next refueling outages are scheduled for 1992. 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.

The 1990 decrease in Federal income tax expense was primarily due to adjustments relating to prior year's 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.

Allowance for Funds Used During Construction and Interest Charges

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.

In 1990 interest expense decreased reflecting the reduction in both long-term and short-term debt outstanding with proceeds from the sale of Rockport 2. 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.

Liquidity and Capital Resources

Construction Spending Decreases

Gross plant and property additions amounted to $162 million in 1990, a 21% decrease from 1989 reflecting the completion of Rockport 2. Construction expenditures for the next three years are estimated at $523 million, exclusive of yet to be determined expenditures necessary to meet the requirements of the Clean Air Act Amendments. 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.

Debt and Preferred Stock Financing

The Company generally issues short-term debt to provide interim financing of construction expenditures in excess of available internally generated funds. At December 31, 1990, the Company had unused short-term lines of credit of $263 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 $90 million. The Company periodically reduces short-term debt with the proceeds of sales of long-term debt and preferred stock securities and investments in its common equity by AEP.

The issuance of senior securities is expected to be relatively modest in the next few years since it is expected that approximately 70% of the Company's projected construction expenditures for 1991-1993 will be financed internally, exclusive of any expenditures necessary to meet the requirements of the recently enacted Clean Air Act Amendments. Additional amounts needed in excess of internally generated funds will be raised externally through sales of securities and investments in the Company's common equity by AEP.

In order to issue additional levels of certain long-term 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. Generally to issue additional levels of 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, 1990, the Company's long-term debt and preferred stock coverage ratios were 3.79 and 2.02, respectively.

In December 1989 the Company and its affiliate, AEP Generating Company (AEGCo), sold their 50% interests in Rockport 2 and leased back the unit. Net proceeds to the Company from the sale were $661 million after taxes. The Company used the proceeds to repay short-term and long-term debt, return capital contributions to its parent and repurchase receivables. The net gain on the sale did not affect 1989 earnings since it was deferred and is being amortized along with applicable deferred taxes over the initial lease term. The leases have been accounted for as operating leases. The substantial increase in cash during 1989 resulted from the Rockport 2 sale proceeds. The substantial amount of taxes paid during 1990 in connection with the sale and leaseback, as well as the related bond and stock redemptions caused the cash decrease in 1990.

Concerns and Contingencies

Clean Air Law — Environmental Costs

In November 1990 the Clean Air Act Amendments became law requiring, among other things, substantial reductions in sulfur dioxide and nitrogen oxide emissions from coal-fired electric generating plants and placing a permanent nationwide limit on emissions after 1999. The new law establishes 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 new amendments. The AEP System is reviewing the amendments and evaluating the compliance alternatives. The compliance alternatives being considered include: (a) installation of new emissions reduction equipment (scrubbers) 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 less substantial capital expenditures and adverse impacts on affiliated mining operations and related facilities; (c) premature retirement of certain existing generating units; and/or (d) significant capital expenditures to repower existing generating units with pressurized fluidized bed combustion (PFBC) technology presently being tested at an affiliate's Tidd PFBC demonstration plant. 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 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 two remaining coal-fired units, Tanners Creek Unit 4 and the Breed Plant, are being studied. As a member of the Power Pool the Company shares in the cost of compliance at generating units owned by other Power Pool member companies. 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 asbestos, polychlorinated biphenyls (PCB's) and other hazardous materials have been employed in the Company's generating plants and transmission/distribution facilities. The Company fully complies with all existing laws regarding handling, transportation, storage and disposal of hazardous and non-hazardous materials it produces or uses. However, 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 Environmental Protection Agency (EPA) to administer them. The Company has been named by the EPA as a "potentially responsible party" for five sites and has received information requests for two other sites. The Company's present estimates do not anticipate material clean up costs. However, should material costs be incurred for the clean up of these sites or for any other site at which the Company may have disposed of materials, the Company's results of operations and financial condition could be adversely impacted unless the costs can be recovered from 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 could 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.

Other New Environmental and Health Concerns

In recent years there has been considerable discussion of environmental and health concerns regarding the emission from generating facilities of "greenhouse" gases such as carbon dioxide 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 evidence. The AEP System will be working to support efforts to properly study "global warming" and EMF and 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 control or limit greenhouse gases and EMF, the Company's results of operations and financial condition could be adversely affected unless the cost of compliance can be recovered from ratepayers.

Regulatory Concerns

In July 1989 the Company filed a request with the Indiana Utility Regulatory Commission (IURC) for an annual increase in rates of $60 million. In August 1990 the IURC granted the Company an increase in rates of $14.3 million. In October 1990 the IURC amended its order, at the Company's request, and allowed an additional $5 million increase in rates. The Company and other parties requested a rehearing of certain portions of the IURC's orders and in February 1991 the IURC issued an order granting rehearing on certain of those issues.

During 1990, the Company filed with the FERC for an $11 million annual rate increase from its firm wholesale customers. In December the FERC granted the Company's request to collect rates designed to produce a $4 million annual increase, subject to refund, pending the issuance of a final order.

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.

In February 1991 the Michigan Public Service Commission (MPSC) granted the Company a $10.4 million annual rate increase from its Michigan retail jurisdictional customers. This rate increase will be effective in two steps: $7.4 million in April 1991 and $3 million in April 1992. The order also places a moratorium on any new base rate filing prior to July 1992 and requires the Company to file an application, within six months, to merge Michigan Power Company, an affiliate, into the Company. It is not presently anticipated that the merger will significantly impact results of operations and financial condition.

Economic Outlook

The economy slowed in 1990 on a national level and to a lesser extent in the Company's service area. Although the slowing economy had minimal effect on 1990 sales levels, further slowdowns or a deep recession could negatively affect demand for energy, especially from industrial customers. With its large industrial base, results of operations for the Company are sensitive to economic conditions which can be impacted by inflation, foreign currency fluctuations, the market price of primary metals, costs of compliance with the Clean Air Act Amendments of 1990 and other matters beyond the control of the Company and its major industrial customers.

Effects of Inflation

Inflation continues to affect the Company, even though the inflation rate has been relatively low in recent years. Since the rate-making process limits the Company to recovery of the historical cost of assets, economic losses are experienced when the effects of inflation are not recovered from customers on a timely basis. Such losses are offset partly by the economic gains that result from the repayment of long-term debt with inflated dollars.

New Accounting Standards

The Financial Accounting Standard Board's (FASB) new accounting standard on income taxes requires the Company to adopt the liability method of accounting for income taxes in 1992 and will result in a significant increase in total assets and liabilities due to the recording of deferred income taxes on timing differences previously flowed through and corresponding offsetting regulatory assets and liabilities. In addition existing deferred taxes will be adjusted to the level required at the currently existing statutory tax rate with an offsetting regulatory asset or liability for deferred tax amounts associated with utility operations. Whether the Company implements the new standard on a restated or prospective basis has not yet been determined. The FASB has indicated that it expects to issue an exposure draft during the first half of 1991 which will amend the new standard and may extend its required effective date until 1993. The Company expects to defer implementation of the new standard until the effective date of the amended standard. It is not presently anticipated that the final standard will significantly impact results of operations or financial condition.

The FASB has issued a new accounting standard that requires a change in accounting for postretirement benefits other than pensions from an expense-as-paid method to an accrual method. This standard permits initial year recognition of the entire prior service cost or recognition of a transition obligation over periods up to 20 years and has an effective date of 1993. The Company expects to elect the 20 year transition option to comply with the new standard. With the assistance of its independent actuary the Company is presently computing its obligation for retiree benefits other than pensions. The Company's obligation is significant as is the difference between the annual accruals required by the new standard under the 20 year transition option and the current pay-as-you-go expense. The Company expects to seek recovery of the increased accruals from ratepayers. Should recovery of or a commitment to recover the required increased accruals beginning in 1993 be denied, the Company's results of operations and possibly its financial condition would be adversely impacted.

Consolidated Statements of Income

	Year Ended December 31,		
	1990	1989	1988
		(in thousands)	
OPERATING REVENUES — ELECTRIC	$1,031,059	$1,005,638	$983,066
OPERATING EXPENSES:			
Fuel	276,719	249,886	232,946
Purchased and Interchange Power (net)	(68,529)	25,376	47,503
Other Operation	244,382	170,855	161,532
Maintenance	134,521	104,223	89,545
Depreciation and Amortization	129,091	124,809	120,145
Amortization of Rockport Plant Unit 1 Phase-in Costs	16,961	16,961	18,089
Taxes Other Than Federal Income Taxes	54,389	56,377	56,271
Federal Income Taxes	42,092	46,755	41,592
Total Operating Expenses	829,626	795,242	767,623
OPERATING INCOME	201,433	210,396	215,443
NONOPERATING INCOME:			
Allowance for Equity Funds Used During Construction	1,174	27,972	27,023
Other	2,772	4,958	16,431
Total Nonoperating Income	3,946	32,930	43,454
INCOME BEFORE INTEREST CHARGES	205,379	243,326	258,897
INTEREST CHARGES:			
Long-term Debt	87,385	131,009	130,649
Short-term Debt and Other	3,158	7,279	6,635
Allowance for Borrowed Funds Used During Construction	(1,479)	(32,107)	(30,192)
Net Interest Charges	89,064	106,181	107,092
NET INCOME	116,315	137,145	151,805
PREFERRED STOCK DIVIDEND REQUIREMENTS	15,587	18,048	18,848
EARNINGS APPLICABLE TO COMMON STOCK	$ 100,728	$ 119,097	$132,957

See Notes to Consolidated Financial Statements.

Consolidated Balance Sheets

	December 31, 1990	December 31, 1989
	(in thousands)	
ASSETS		
ELECTRIC UTILITY PLANT:		
Production	$2,473,678	$2,465,133
Transmission	778,115	777,782
Distribution	482,324	452,780
General (includes nuclear fuel)	182,906	170,349
Construction Work in Progress	94,441	52,572
Total Electric Utility Plant	4,011,464	3,918,616
Accumulated Depreciation and Amortization	1,403,871	1,292,430
Net Electric Utility Plant	2,607,593	2,626,186
OTHER PROPERTY AND INVESTMENTS	343,307	321,215
CURRENT ASSETS:		
Cash and Cash Equivalents	2,721	595,487
Accounts Receivable:		
Customers	70,677	114,350
Affiliated Companies	26,926	10,669
Miscellaneous	25,237	23,441
Allowance for Uncollectible Accounts	(674)	(606)
Fuel — at average cost	54,790	40,057
Materials and Supplies — at average cost	38,483	32,479
Accrued Utility Revenues	39,085	35,885
Other	11,860	6,920
Total Current Assets	269,105	858,682
DEFERRED DEBITS:		
Deferred Taxes — Gain on Sale and Leaseback of Rockport Plant Unit 2	176,967	183,290
Deferred Depreciation and Return — Rockport Plant Unit 1	114,918	131,879
Deferred Nuclear Fuel Disposal Costs	43,615	47,822
Other	79,930	90,752
Total Deferred Debits	415,430	453,743
Total	$3,635,435	$4,259,826

See Notes to Consolidated Financial Statements.

	December 31, 1990	December 31, 1989
	(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	145,489	157,825
Total Common Shareowner's Equity	919,682	932,018
Cumulative Preferred Stock — Not Subject to Mandatory Redemption	197,000	197,000
Long-term Debt	1,072,333	1,021,566
Total Capitalization	2,189,015	2,150,584
OTHER NONCURRENT LIABILITIES	220,127	190,962
CURRENT LIABILITIES:		
Cumulative Preferred Stock Due Within One Year	—	18,030
Long-term Debt Due Within One Year	51,500	501,170
Commercial Paper	33,945	—
Accounts Payable:		
General	62,343	52,602
Affiliated Companies	16,831	35,811
Taxes Accrued	—	200,787
Interest Accrued	21,900	36,101
Obligations Under Capital Leases	36,399	33,247
Other	55,471	76,878
Total Current Liabilities	278,389	954,626
DEFERRED CREDITS:		
Deferred Income Taxes	478,005	485,444
Deferred Investment Tax Credits	212,913	221,666
Deferred Gain on Sale and Leaseback — Rockport Plant Unit 2	234,303	241,255
Other	22,683	15,289
Total Deferred Credits	947,904	963,654
COMMITMENTS AND CONTINGENCIES (Note 10)		
Total	$3,635,435	$4,259,826

Consolidated Statements of Cash Flows

	Year Ended December 31, 1990	1989	1988
		(in thousands)	
Operating Activities:			
Net Income	$ 116,315	$ 137,145	$ 151,805
Adjustments for Noncash Items:			
Depreciation and Amortization	138,747	133,551	128,191
Amortization of Rockport Plant Unit 1 Phase-in Costs	16,961	16,961	18,089
Amortization of Deferred Nuclear Fuel Disposal Costs	4,207	3,204	5,408
Deferred Income Taxes	(8,804)	(196,977)	3,161
Deferred State Taxes — Rockport Plant Unit 2 Sale and Leaseback Transaction	1,937	(39,943)	—
Deferred Investment Tax Credits	(8,248)	27,445	23,672
Allowance for Equity Funds Used During Construction	(1,174)	(27,972)	(27,023)
Changes in Certain Current Assets and Liabilities:			
Accounts Receivable (net)	25,688	(79,755)	25,530
Fuel, Materials and Supplies	(20,737)	4,682	16,485
Accrued Utility Revenues	(3,200)	(8,373)	24,064
Accounts Payable	(9,239)	18,367	11,019
Taxes Accrued	(200,787)	196,502	(41,913)
Interest Accrued	(14,201)	(252)	(759)
Other (net)	(6,919)	26,510	26,704
Net Cash Flows From Operating Activities	30,546	211,095	364,433
Investing Activities:			
Construction Expenditures	(104,494)	(196,824)	(276,545)
Allowance for Equity Funds Used During Construction	1,174	27,972	27,023
Cash Used for Construction Expenditures	(103,320)	(168,852)	(249,522)
Proceeds from Sale and Leaseback — Rockport Plant Unit 2	—	850,000	—
Proceeds from Sales of Other Property	6,039	1,381	1,117
Net Cash Flows From (Used For) Investing Activities	(97,281)	682,529	(248,405)
Financing Activities:			
Capital Contributions From (Returned to) Parent	—	(63,000)	10,000
Issuance of Long-term Debt	40,000	—	50,000
Change in Short-term Debt (net)	33,945	(35,850)	35,850
Retirement of Cumulative Preferred Stocks	(19,048)	(7,000)	(7,000)
Retirement of Long-term Debt	(451,770)	(62,512)	(74,050)
Dividends Paid on Common Stock	(113,064)	(119,952)	(116,816)
Dividends Paid on Cumulative Preferred Stock	(16,094)	(18,248)	(19,048)
Net Cash Flows Used For Financing Activities	(526,031)	(306,562)	(121,064)
Net Increase (Decrease) in Cash and Cash Equivalents	(592,766)	587,062	(5,036)
Cash and Cash Equivalents January 1	595,487	8,425	13,461
Cash and Cash Equivalents December 31	$ 2,721	$ 595,487	$ 8,425

See Notes to Consolidated Financial Statements.

Consolidated Statements of Retained Earnings

	Year Ended December 31,		
	1990	1989	1988
		(in thousands)	
Retained Earnings January 1	$157,825	$161,443	$145,302
Net Income	116,315	137,145	151,805
	274,140	298,588	297,107
Cash Dividends Declared:			
Common Stock	113,064	119,952	116,816
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	1,198
$2.15 Series	3,440	3,440	3,440
$2.25 Series	3,600	3,600	3,600
$2.75 Series	122	1,793	2,233
Total Dividends	128,651	138,000	135,664
Net Premium on Reacquisition of Preferred Stock	—	2,763	—
Total Deductions	128,651	140,763	135,664
Retained Earnings December 31	$145,489	$157,825	$161,443

See Notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements

1. Significant Accounting Policies:

Principles of Consolidation

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

System of Accounts

The accounting and rates of the Company are subject in certain respects to the requirements of state regulatory commissions and the Federal Energy Regulatory Commission (FERC). The financial statements of the Company have been prepared on the basis of the uniform system of accounts prescribed by the FERC.

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 rates used by the Company after compounding on a semi-annual basis were 10.5% in 1990 and 1989 and 10.25% in 1988.

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

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 a maturity of three months or less.

Income Taxes

Deferred income taxes are provided except where not permitted by the state commissions and the FERC. The Company deferred and is amortizing over the life of its plant the effect of tax reductions resulting from investment tax credits utilized in connection with current Federal income tax accruals 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

The common stock of the Company is wholly owned by American Electric Power Company, Inc. (AEP).

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 in accordance with rate-making treatment.

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

Certain prior-period amounts have been reclassified to conform to current-period presentation.

2. Rate Matters:

Rockport Plant Unit 1 Phase-in Plan

The Company has phase-in plans in its Indiana and FERC jurisdictions for Rockport Plant Unit 1 (Rockport 1). Rockport 1 is a 1,300 megawatt (mw) generating unit that began commercial operation in December 1984 and is jointly and equally owned by the Company and AEGCo. At December 31, 1990 and 1989, the Company had unamortized deferred returns of \$89,061,000 and \$102,206,000, respectively, and unamortized deferred depreciation of \$25,857,000 and \$29,673,000, respectively. These deferrals are being amortized on a straight-line basis through 1997 and recovered in rates.

Rockport Plant Unit 2 Sale and Leaseback and Rate Recovery

The Company and AEGCo constructed a second 1,300 mw unit at the Rockport Plant (Rockport 2) at a cost of \$1.3 billion. The unit began commercial operation on December 1, 1989. On December 7, 1989, the Company and AEGCo sold their respective 50% interests in the unit for \$1.7 billion, the estimated fair market value, and leased back 50% interests in Rockport 2 for an initial term of 33 years. The gain from the sale was deferred and is being amortized, including related taxes, over the initial lease term. The leases have been accounted for as operating leases.

The Company will receive 1,105 mw of Rockport 2 capacity, comprised of 650 mw, its 50% share, and 455 mw it is obligated to purchase from AEGCo under the terms of a long-term unit power agreement. In July 1989, the Company filed a request with the Indiana Utility Regulatory Commission (IURC) for an increase in rates of approximately \$60,000,000 annually to recover, among other things, the Company's Indiana jurisdictional share of the cost of 385 mw of Rockport 2 capacity purchased from AEGCo. The rate request did not seek recovery of the cost of the remaining 720 mw of Rockport 2 energy since it was based on the assumption that the 720 mw would be sold to unaffiliated utilities. In August 1990 the IURC granted the Company an increase in rates of \$14.3 million. In October 1990 the IURC amended its order and allowed an additional \$5 million increase in rates. The Company has been granted a rehearing of certain other portions of the IURC's August order.

The Company has entered into a long-term unit power agreement with Carolina Power & Light (CPL), an unaffiliated utility, to supply 250 mw of Rockport 2 capacity for a 20-year period that began in January 1990. The FERC allowed the agreement to become effective subject to refund pending a hearing and final order. During 1990, the FERC resolved the pending issues and the Company made refunds as ordered. Unless the Company sells the remaining 470 mw of Rockport 2 capacity on a long-term basis it is contributed to the AEP System Power Pool (Power Pool). The Company will share with the other members of the Power Pool in the cost of the remaining uncommitted Rockport 2 capacity. Future results of operations will be impacted unless the Power Pool can sell the additional capacity.

Coal and Transportation Charges

In June 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 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.

3. Federal Income Taxes:

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

	Year Ended December 31, 1990	1989	1988
		(in thousands)	
Charged (Credited) to Operating Expenses (net):			
Current	$52,894	$ 215,793	$11,865
Deferred	(5,043)	(196,503)	5,563
Deferred Investment Tax Credits	(5,759)	27,465	24,164
Total	42,092	46,755	41,592
Charged (Credited) to Nonoperating Income (net):			
Current	7,288	1,234	1,186
Deferred	(3,761)	(474)	(2,402)
Deferred Investment Tax Credits	(2,489)	(20)	(492)
Total	1,038	740	(1,708)
Total Federal Income Taxes as Reported	$43,130	$ 47,495	$39,884

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 in the Consolidated Statements of Income.

	Year Ended December 31, 1990	1989	1988
		(in thousands)	
Net Income	$116,315	$137,145	$151,805
Federal Income Taxes	43,130	47,495	39,884
Pre-tax Book Income	$159,445	$184,640	$191,689
Federal Income Taxes on Pre-Tax Book Income at Statutory Rate (34%)	$ 54,211	$ 62,778	$ 65,174
Increase (Decrease) in Federal Income Taxes Resulting From the Following Items on Which Deferred Taxes Are Not Provided:			
Allowance for Equity Funds Used During Construction Net of Amortization of Prior Year Deferred Taxes for Items Capitalized on the Books but Deducted for Tax Purposes	(2,476)	(12,664)	(12,079)
Mine Development and Mineral Rights Amortization	4,369	3,048	2,293
Tax Exempt Income — Nuclear Decommissioning Trust Funds	(480)	(383)	(4,066)
Other	(1,684)	1,111	(4,481)
Amortization of Deferred Investment Tax Credits	(10,810)	(6,395)	(6,957)
Total Federal Income Taxes as Reported	$ 43,130	$ 47,495	$ 39,884
Effective Federal Income Tax Rate	27.1%	25.7%	20.8%

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

	Year Ended December 31,		
	1990	1989	1988
		(in thousands)	
Current:			
Federal Income Taxes	$62,744	$250,867	$ 43,680
Investment Tax Credits	(2,562)	(33,840)	(30,629) (b)
Total Current Federal Income Taxes	60,182	217,027 (a)	13,051
Deferred:			
Depreciation	1,041	2,254	4,737
Allowance for Borrowed Funds Used During Construction and Miscellaneous Items Capitalized	(2,953)	7,109	5,186
Unrecovered and Levelized Fuel	4,214	(5,453)	(8,278)
Nuclear Decommissioning Costs	(756)	(514)	16,432 (c)
Unbilled Revenue	(3,349)	(3,713)	(4,202)
Deferred Return — Rockport Plant Unit 1	(2,864)	(2,864)	(3,538)
Sale of Rockport Plant Unit 2	—	(56,863)	—
Deferred Net Gain — Sale of Rockport Plant Unit 2	3,457	(128,194)	—
Other	(7,594)	(8,739)	(7,176)
Total Deferred Federal Income Taxes	(8,804)	(196,977)	3,161
Total Deferred Investment Tax Credits	(8,248)	27,445 (a)	23,672 (b)
Total Federal Income Taxes as Reported	$43,130	$ 47,495	$ 39,884

(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.

(b) Based on Internal Revenue Service regulations issued in 1988, the Company elected to claim investment tax credits on qualified progress expenditures on the 1987 tax return and amended tax returns for 1975 through 1986. The current and deferred tax effects recorded during 1988 represent the cumulative effect of this election as well as 1988 current year accruals.

(c) Based on a ruling the Company received from the Internal Revenue Service in 1988, the Company elected to deduct nuclear decommissioning costs on the 1987 tax return and on amended tax returns for the years 1984 through 1986. The current and deferred tax effects recorded during 1988 represent the cumulative effect of this election as well as 1988 current year accruals.

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 Securities and Exchange Commission (SEC) rules under the Public Utility Holding Company Act of 1935 (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, 1990, the cumulative net amount of income tax timing differences on which deferred taxes have not been provided totaled $448,000,000.

The consolidated Federal income tax returns for the years 1983 through 1987 are being audited by the Internal Revenue Service. In the opinion of management, the final settlement of open years should not have a material effect on the earnings of the Company.

In December 1987, the Financial Accounting Standards Board (FASB) issued SFAS 96 "Accounting for Income Taxes" which requires that companies adopt the liability method of accounting for income taxes. Presently SFAS 96 must be adopted by the Company by January 1992 on a restated basis or as a cumulative effect of an accounting change in the year of adoption. However, the FASB has indicated that they expect to issue an exposure draft during the first half of 1991 which will amend SFAS 96 and may extend its required effective date until January 1993. 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 offsetting regulatory assets and liabilities. In addition, existing deferred taxes will be adjusted to the level required at the currently existing statutory tax rate which will be offset by a regulatory asset or liability for deferred tax amounts associated with utility operations. It is not presently anticipated that the final standard will significantly impact results of operations or financial condition. Whether the new standard will be implemented on a restated or prospective basis has not yet been determined.

4. Related-party Transactions:

Operating revenues shown in the Consolidated Statements of Income include sales of energy to Michigan Power Company, an affiliated utility that is not a member of the Power Pool, of approximately $31,000,000, $32,000,000 and $34,000,000 for the years ended December 31, 1990, 1989 and 1988, respectively.

The Company purchases power and engages in interchange power transactions to exchange energy with affiliated and unaffiliated utilities as follows:

	Year Ended December 31,		
	1990	1989	1988
		(in thousands)	
Purchased and Interchange Power (net):			
Purchased Power:			
AEP Generating Company (a) .	$ 78,990	$ 13,023	$ 3,313
Ohio Valley Electric Corporation (a)	529	5,623	13,580
Unaffiliated Companies ...	28,196	21,486	7,478
Net Interchange Power:			
AEP Power Pool Member Utilities:			
Capacity Charge (Credit) . .	(98,664)	4,558	14,332
Energy Charge (Credit) . .	(77,913)	(17,858)	9,858
Unaffiliated Companies ...	333	(1,456)	(1,058)
Total	$(68,529)	$ 25,376	$47,503

(a) Affiliated utilities that are not members of the Power Pool.

The Company is a member of the 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 short-term wholesale sales to unaffiliated utilities made by the Power Pool. The Company's share was credited to operating revenues in the amount of $126,005,000, $126,065,000 and $74,181,000 in 1990, 1989 and 1988, respectively. The Company became a net supplier of capacity to the Power Pool with commercial operation of Rockport 2 in December 1989. Accordingly the Company received capacity and energy credits resulting in a reduction of total purchased and interchange power expense in 1989 and a further reduction to a net credit in 1990.

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 $47,586,000, $37,346,000 and $36,996,000 for transmission services in 1990, 1989 and 1988, respectively.

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

	Year Ended December 31,		
	1990	1989	1988
		(in thousands)	
Affiliated Companies	$17,094	$21,092	$10,349
Unaffiliated Companies	2,882	5,173	7,131
Total	$19,976	$26,265	$17,480

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

5. Common Shareowner's Equity:

In December 1989 the Company returned $63,000,000 of cash capital contributions to its parent from paid-in capital. The Company received $10,000,000 of capital contributions in 1988. In 1989, the Company recorded charges of $1,154,000 to paid-in capital and $2,763,000 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 1990, 1989 or 1988.

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 stocks and for other purposes. At December 31, 1990, approximately $45,900,000 of retained earnings were restricted. In addition, regulatory approval is required for the Company to pay dividends out of paid-in capital.

6. Cumulative Preferred Stock:

At December 31, 1990, authorized shares of cumulative preferred stock were as follows:

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

The cumulative preferred stock is callable at the 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.

A. Cumulative Preferred Stock Not Subject To Mandatory Redemption:

Series	Call Price December 31, 1990	Par Value	Shares Outstanding December 31, 1990	Amount December 31, 1990	Amount December 31, 1989
				(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%	102.91	100	300,000	30,000	30,000
7.76%	103.44	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

B. Cumulative Preferred Stock Subject to Mandatory Redemption:

Series	Par Value	Number of Shares Redeemed Year Ended December 31, 1990	1989	1988	Shares Outstanding December 31, 1990	Amount December 31, 1990	Amount December 31, 1989
						(in thousands)	
12%	$100	47,325	30,000	30,000	–	–	$ 4,733
$2.75	25	531,900	160,000	160,000	–	–	13,297
						–	$18,030

7. Long-term Debt and Lines of Credit

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

	December 31, 1990	December 31, 1989
	(in thousands)	
First Mortgage Bonds	$ 599,179	$1,007,744
Sinking Fund Debentures	6,188	6,492
Notes Payable to Banks	80,000	80,000
Installment Purchase Contracts	308,175	307,953
Other Long-term Debt (a)	130,291	120,547
	1,123,833	1,522,736
Less Portion Due Within One Year	51,500	501,170
Total	$1,072,333	$1,021,566

(a) Nuclear Fuel Disposal Costs including interest accrued. See Note 10.

First mortgage bonds outstanding were as follows:

% Rate	Due	December 31, 1990	December 31, 1989
		(in thousands)	
4⅜	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)	173,500	185,000
8⅜	2003 — December 1	40,000	40,000
9½	2008 — March 1	34,034	100,000
13¾	2013 — August 1	—	58,704
9⅝	2015 — October 1	—	100,000
9¾	2016 — July 1	—	100,000
8¾	2017 — February 1	100,000	100,000
10⅛	2017 — May 1	—	75,000
Unamortized Discount (net)		(1,257)	(3,862)
		599,179	1,007,744
Less Portion Due Within One Year		11,500	411,170
Total		$587,679	$ 596,574

(a) The 9½% series due 2003 requires sinking fund payments of $11,500,000 on June 1, 1991 and $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, 1990 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, 1990	December 31, 1989
	(in thousands)	
9.12% due 1990	$ —	$20,000
9.18% due 1990	—	20,000
9.28% due 1991	20,000	20,000
9.28% due 1991	20,000	20,000
9.07% due 1995	40,000	—
Total	$80,000	$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, 1990	December 31, 1989
		(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	6,500
9¼	2010 — June 1	33,500	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
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		(3,825)	(4,047)
Total		$308,175	$307,953

(a) The adjustable interest rate changed from 7½% on August 1, 1990 and will change every five years thereafter.

(b) The variable interest rate is determined weekly. The average weighted interest was 6.5% for 1990 and 7.0% for 1989.

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. Certain series are supported by bank letters of credit which expire in 1995.

Long-term debt, excluding premium or discount, outstanding at December 31, 1990 is due as follows:

	Principal Amount (in thousands)
1991	$ 51,500
1992	13,500
1993	56,402
1994	13,500
1995	53,500
Later Years	940,513
Total	$1,128,915

The amount of short-term debt the Company may borrow is limited by the provisions of the 1935 Act to $200,000,000 and further limited by provision of the charter to $90,000,000. The Company shares bank lines of credit with other AEP System companies and at December 31, 1990 and 1989 had unused shared lines of $263,000,000 and $233,000,000, 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 of up to ¼ of 1% a year are required to maintain the lines of credit.

8. 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.

In 1990 the Company replaced its nuclear fuel leases with a financial institution by entering into a new nuclear fuel leasing agreement with 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 nuclear fuel leases as capital leases.

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

	December 31, 1990	December 31, 1989
	(in thousands)	
Electric Utility Plant:		
Production	$ 9,090	$ 8,835
Distribution	14,607	14,603
General:		
Nuclear Fuel (net of amortization)	96,914	88,328
Other	38,013	34,777
Total Electric Utility Plant	158,624	146,543
Accumulated Amortization	25,675	23,783
Net Electric Utility Plant	132,949	122,760
Other Property	2,008	16,746
Accumulated Amortization	1,893	16,529
Net Other Property	115	217
Net Properties under Capital Leases	$133,064	$122,977
Obligations under Capital Leases (a)	$133,064	$122,977

(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, 1990:

	Capital Leases	Operating Leases
	(in thousands)	
1991	$ 7,535	$ 94,791
1992	6,631	91,557
1993	5,415	91,267
1994	4,669	90,897
1995	4,351	90,483
Later Years	34,167	2,180,708
Total Future Minimum Lease Payments	62,768	$2,639,703
Less Estimated Interest Element	26,618	
Estimated Present Value of Future Minimum Lease Payments	36,150	
Unamortized Nuclear Fuel	96,914 (a)	
Total	$133,064	

(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 $49,990,000, $59,212,000 and $52,568,000 were charged to fuel expense in 1990, 1989 and 1988, 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.

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,		
	1990	1989	1988
		(in thousands)	
Operating Leases	$ 87,357	$16,454	$16,661
Capital Leases:			
Amortization of Principal	46,836	52,815	49,014
Interest	10,877	13,733	11,690
Total Rental Payments	$145,070	$83,002	$77,365

9. 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 required contribution.

Net pension costs for the years ended December 31, 1990, 1989 and 1988 were $2,726,000, $1,271,000 and $397,000, respectively.

The Company offers an employee savings plan under which eligible participants can invest from 1% to 16% of their salaries among several investment alternatives, including AEP common stock. An employer contribution equal to one-half of the first 6% of the employees' contribution is invested in AEP common stock. The Company's annual contributions were $2,822,000 in 1990, $2,726,000 in 1989 and $2,312,000 in 1988.

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 these benefits if they have 10 years of health care plan participation at retirement. The cost of retiree benefits is recognized as an expense when paid. In 1990, 1989 and 1988, the cost of retiree health care benefits totaled $2,580,000, $2,121,000 and $2,048,000, respectively.

The FASB has issued SFAS 106 "Employers' Accounting for Postretirement Benefits Other Than Pensions" which requires employers, beginning in 1993, to accrue for the costs of retiree health care benefits. SFAS 106 permits the recognition of the transition obligation (the unfunded and unrecognized accumulated postretirement benefit obligation) in the initial year of implementation or over periods up to 20 years. The Company expects to elect the 20 year transition option. In anticipation of this new requirement, the Company made a $4.1 million contribution in 1990, the maximum amount deductible for Federal income tax purposes, to a Voluntary Employee Beneficiary Association (VEBA) trust fund for postretirement benefits other than pensions. Another measure taken by the Company 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 generated a substantial cash surrender value which is recorded, net of equally substantial policy loans, as other property and investments. In future years the policies are expected to generate significant cash flows which will be contributed to the VEBA trust fund. The annual accruals required by SFAS 106 are expected to be significantly greater than the currently recognized pay-as-you-go expenses. The Company expects to seek recovery of the increased accruals from ratepayers. Should recovery of or a commitment to recover the SFAS 106 accruals beginning in 1993 be denied, the Company's results of operations and possibly its financial condition would be adversely impacted.

10. Commitments and Contingencies:

Construction

The construction budget of the Company and its subsidiaries for the years 1991-1993 is estimated at $523,000,000, and, in connection therewith, commitments have been made.

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. As a result the annual loss of revenue is expected to be $500,000 rather than the potential $7 million loss previously reported.

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 when the service was rendered in accordance with an IURC order which the Company believed in good faith to be valid.

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 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.

On November 15, 1990 President Bush signed into law the Clean Air Act Amendments of 1990 which, among other things, requires significant reductions in the emission of sulfur dioxide and nitrogen oxide from various existing System generating plants. With respect to acid rain control the new law establishes a strict timetable for compliance setting 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 is reviewing the provisions of the new law and evaluating compliance alternatives which include: (a) installation of new emissions reduction equipment (scrubbers) 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 less substantial capital expenditures and adverse impacts on affiliated mining operations and related facilities; (c) premature retirement of certain generating units; and/or (d) significant capital expenditures to repower existing generating units with pressurized fluidized bed combustion (PFBC) technology presently being tested at an affiliate's Tidd PFBC demonstration plant. The cost of compliance for certain of the Company's generating units and the Company's share of such costs through the Power Pool will be substantial. Unless these costs are recovered through rates, the Company's results of operations will be adversely affected.

Recent concerns about global warming have led to international negotiations and proposed legislation to stabilize or reduce "greenhouse" gases such as carbon dioxide. Proposed legislation, passed by the U.S. Senate in the last session of Congress, is expected to be considered in the current session of Congress. 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.

Long-term Power Sales

The Company as a member of the Power Pool has participated in a long-term contract for the sale of up to 560 mw of power to an unaffiliated utility that expired December 31, 1990 and was not renewed. This contract contributed $16 million to the Company's revenues and $5 million to net income in 1990. The Power Pool is attempting to replace the terminated sales with new transactions with unaffiliated utilities. Recently, an agreement was reached to sell 100 mw under a long-term contract with an unaffiliated utility. Whether the Power Pool will be successful in negotiating additional transactions to take the place of the expired contract cannot presently be determined.

Nuclear Insurance

The Company is subject to the Price-Anderson Act which limits the public liability of a licensee of a nuclear plant for a single nuclear incident to the amount of primary liability insurance available from private sources and an industry retrospective deferred premium assessment plan. Based on 115 reactors currently being subject to the Act, the limit of public liability is $7.8 billion. The Company maintains the maximum private insurance available of $200,000,000 for its two-unit Donald C. Cook Nuclear Plant (Cook Plant). The maximum standard deferred premium that the Company may be assessed, in the event of a nuclear incident at any licensed nuclear power plant in the United States, is $63,000,000 per reactor, but an assessment may not exceed $10,000,000 in any one year. If public liability claims and authorized legal costs 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 and costs. 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 $126,000,000 for its two reactors, in annual installments of $20,000,000, plus $6,300,000 for excess claims and costs. 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 for loss resulting from damage to the Cook Plant facilities in the amount of $2.185 billion. Nuclear insurance pools provide $1.06 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 $7.6 million. Nuclear Regulatory Commission (NRC) regulations require that, in the event of an accident, whenever the estimated costs of reactor stabilization and site decontamination exceed $100 million, 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 in accordance with a plan approved by the NRC. The insurers then would indemnify the Company for property damage up to $1.985 billion less any amounts used for stabilization and decontamination. The remaining $200 million, as provided by NEIL, (reduced by any stabilization and decontamination expenditures over $1.985 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 of replacement power resulting from a prolonged accidental outage of a nuclear unit. The Company's policy insures against such increased costs up to approximately $1.8 million per week (starting 21 weeks after the outage) for one year, $1.2 million per week for the second year and $600,000 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 $4.6 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 costs of replacement power in the event of a nuclear incident at the Cook Plant. Future losses or liabilities which are not completely insured, unless recovered through rates, could have a material adverse effect on the financial condition of the Company.

Disposal of Spent Nuclear Fuel and Nuclear Decommissioning

The Nuclear Waste Policy Act of 1982 as amended establishes Federal responsibility for the permanent disposal of spent nuclear fuel. Disposal costs are paid by fees assessed against owners of nuclear plants and deposited into the Nuclear Waste Fund created by the Act. In 1983 the Company entered into a contract with the U.S. Department of Energy (DOE) for the disposal of spent nuclear fuel. Under terms of the contract, for the disposal of nuclear fuel consumed after April 6, 1983 by the Cook Plant, the Company is paying to the fund a fee of one mill per kilowatthour, which the Company is currently recovering from its customers. For the disposal of nuclear fuel consumed prior to April 7, 1983, the Company must pay over a period of 10 years to the U.S. Treasury an estimated fee of $71,964,000, exclusive of interest. The Company has deferred this amount plus accrued interest on its balance sheet, has received regulatory approval for the recovery of this amount and is amortizing the amount deferred as it is being recovered. Because of the current uncertainties of DOE's program for permanent disposal of spent nuclear fuel, the Company has not yet commenced paying this fee.

An independent consulting firm employed by the Company has estimated that the cost of decommissioning the Cook Plant could range from $330,000,000 to $369,000,000 in 1989 dollars. The Company has received regulatory approval from all of its jurisdictions for the recovery of such nuclear decommissioning costs associated with the Cook Plant which amounted to $10,000,000 before income taxes in 1990. The Company intends to reevaluate periodically amounts collected for such costs and to seek regulatory approval to revise such amounts as necessary.

Funds recovered through the rate-making process for disposal of spent nuclear fuel consumed prior to April 7, 1983 and for nuclear decommissioning have been deposited in external funds for the future payment of such costs.

11. Supplementary Information:

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

	Year Ended December 31,		
	1990	1989	1988
		(in thousands)	
Real and Personal Property	$26,946	$ 31,897	$32,339
State Gross Receipts, Excise, Franchise and Miscellaneous State and Local	12,156	29,282	12,361
State Income	5,760	28,057	4,913
Payroll	7,590	7,084	6,658
Deferred Taxes — Rockport 2 Sale and Leaseback Transaction	1,937	(39,943)	—
Total	$54,389	$ 56,377	$56,271

The following are the amounts of cash paid for:

	Year Ended December 31,		
	1990	1989	1988
		(in thousands)	
Interest (net of capitalized amounts)	$101,905	$107,124	$106,283
Income Taxes	247,172	64,843	67,019

The amounts of non-cash investing acquisitions under capital leases were $57,112,000 in 1990, $9,035,000 in 1989 and $46,791,000 in 1988.

12. 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	Operating Income	Net Income
		(in thousands)	
1990			
March 31	$253,075	$59,281	$37,699
June 30	248,460	48,733	27,442
September 30	264,782	52,886	32,077
December 31	264,742	40,533	19,097
1989			
March 31	257,688	51,568	36,352
June 30	244,738	46,239	28,028
September 30	249,761	56,242	40,357
December 31	253,451	56,347	32,408

Independent Auditors' Report

Deloitte &
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, 1990 and 1989, and the related consolidated statements of income, retained earnings, and cash flows for each of the three years in the period ended December 31, 1990. 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, 1990 and 1989, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1990 in conformity with generally accepted accounting principles.

Deloitte & Touche

February 26, 1991

Operating Statistics

	1990	1989	1988	1987	1986
Electric Operating Revenues (in thousands):					
From Kilowatt-hour Sales:					
Retail:					
Residential:					
Without Electric Heating	**$ 179,955**	$ 182,786	$189,845	$ 186,418	$ 174,550
With Electric Heating	**86,108**	93,291	96,145	90,261	90,881
Total Residential	**266,063**	276,077	285,990	276,679	265,431
Commercial	**195,184**	196,404	194,982	191,352	184,276
Industrial	**228,927**	233,990	233,855	235,470	219,344
Miscellaneous	**11,273**	11,475	11,645	11,533	11,171
Total Retail	**701,447**	717,946	726,472	715,034	680,222
Wholesale (sales for resale)	**314,351**	274,916	248,283	293,379	400,779
Total from Kilowatt-hour Sales	**1,015,798**	992,862	974,755	1,008,413	1,081,001
Provision for Revenue Refunds	**—**	—	(1,800)	—	541
Total Net of Provision for Revenue Refunds	**1,015,798**	992,862	972,955	1,008,413	1,081,542
Other Operating Revenues	**15,261**	12,776	10,111	8,855	9,753
Total Electric Operating Revenues	**$1,031,059**	$1,005,638	$983,066	$1,017,268	$1,091,295

	1990	1989	1988	1987	1986
Sources and Sales of Energy (in millions of kilowatt-hours):					
Sources:					
Net Generated:					
Fossil Fuel	**14,451**	10,634	8,707	6,662	8,187
Nuclear Fuel	**11,115**	12,094	9,791	10,060	10,986
Hydroelectric	**116**	97	70	62	79
Total Net Generated	**25,682**	22,825	18,568	16,784	19,252
Purchased	**4,724**	2,229	1,700	2,558	4,941
Net Interchange	**(5,973)**	(1,942)	737	1,947	542
Total Sources	**24,433**	23,112	21,005	21,289	24,735
Less: Losses, Company Use, Etc.	**1,590**	1,606	1,630	1,456	1,645
Net Sources	**22,843**	21,506	19,375	19,833	23,090
Sales:					
Retail:					
Residential:					
Without Electric Heating	**2,774**	2,792	2,825	2,719	2,536
With Electric Heating	**1,484**	1,585	1,571	1,445	1,442
Total Residential	**4,258**	4,377	4,396	4,164	3,978
Commercial	**3,388**	3,375	3,290	3,142	3,007
Industrial	**5,140**	5,168	5,036	4,834	4,371
Miscellaneous	**221**	228	228	221	212
Total Retail	**13,007**	13,148	12,950	12,361	11,568
Wholesale (sales for resale)	**9,836**	8,358	6,425	7,472	11,522
Total Sales	**22,843**	21,506	19,375	19,833	23,090

OPERATING STATISTICS (Concluded)

	1990	1989	1988	1987	1986
AVERAGE COST OF FUEL CONSUMED (in cents):					
Per Million Btu:					
Coal	**145**	164	182	190	185
Nuclear	**58**	61	70	75	74
Overall	**105**	106	120	117	118
Per Kilowatt-hour Generated:					
Coal	**1.42**	1.62	1.81	1.87	1.82
Nuclear	**.64**	.67	.77	.84	.83
Overall	**1.08**	1.11	1.26	1.25	1.25
RESIDENTIAL SERVICE — AVERAGES:					
Annual Kwh Use per Customer:					
Total	**10,047**	10,434	10,596	10,146	9,813
With Electric Heating	**16,979**	18,447	18,551	17,341	17,716
Annual Electric Bill:					
Total	**$627.84**	$658.08	$689.33	$674.13	$654.88
With Electric Heating	**$985.16**	$1,085.56	$1,135.46	$1,083.10	$1,116.86
Price per Kwh (in cents):					
Total	**6.25**	6.31	6.51	6.64	6.67
With Electric Heating	**5.80**	5.88	6.12	6.25	6.30
NUMBER OF ELECTRIC CUSTOMERS:					
Year-End:					
Retail:					
Residential:					
Without Electric Heating	**338,171**	335,625	332,488	328,937	325,623
With Electric Heating	**88,258**	87,016	85,635	84,442	82,324
Total Residential	**426,429**	422,641	418,123	413,379	407,947
Commercial	**47,020**	46,176	45,249	44,207	43,689
Industrial	**4,494**	4,485	4,479	4,345	3,882
Miscellaneous	**2,018**	2,026	1,984	1,946	1,846
Total Retail	**479,961**	475,328	469,835	463,877	457,364
Wholesale (sales for resale)	**54**	50	108	105	106
Total Electric Customers	**480,015**	475,378	469,943	463,982	457,470

Dividends and Price Ranges of Cumulative Preferred Stock

By Quarters (1990 and 1989)

	1990 — Quarters				1989 — 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	—	—	—	—	—	—	—	—
— Low	—	—	—	—	—	—	—	—
4.56% Series								
Dividends Paid Per Share	$1.14	$1.14	$1.14	$1.14	$1.14	$1.14	$1.14	$1.14
Market Price — $ Per Share								
(OTC)								
Ask (high/low)	—	—	—	—	—	—	—	—
Bid (high/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)	—	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	78	75	77	75	71	76	77	77⅝
— Low	73	72	73	72	66½	68	73⅜	75
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	83	79	81	83	77⅝	85¼	85¼	84⅜
— Low	76½	77¼	76½	76¾	74	74½	80	80⅞
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	88½	87¼	88¾	91	84½	88½	92	92
— Low	85½	85⅛	85¼	84¾	81½	81½	86	89
12% Series (a)								
Dividends Paid Per Share	$1.00				$3.00	$3.00	$3.00	$3.00
Market Price — $ Per Share								
(NYSE) — High	107½				103½	106½	106	108
— Low	105¾				101	102½	103	104
($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	23⅜	22⅞	23¼	24⅜	22⅞	23	24⅜	24
— Low	21⅝	21⅜	21¾	22½	21	20¾	22	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	24⅜	23⅞	23½	24⅜	23⅛	24	24⅝	25⅛
— Low	22⅞	22½	22⅝	23⅜	21½	21⅝	23¼	23⅝
$2.75 Series (a)								
Dividends Paid Per Share	$0.229				$0.6875	$0.6875	$0.6875	$0.6875
Market Price — $ Per Share								
(NYSE) — High	27				26½	27½	27½	27
— Low	26¾				26	25½	26	26¼

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 1991 to shareowners
upon written request and at no cost.
Please address such requests to:

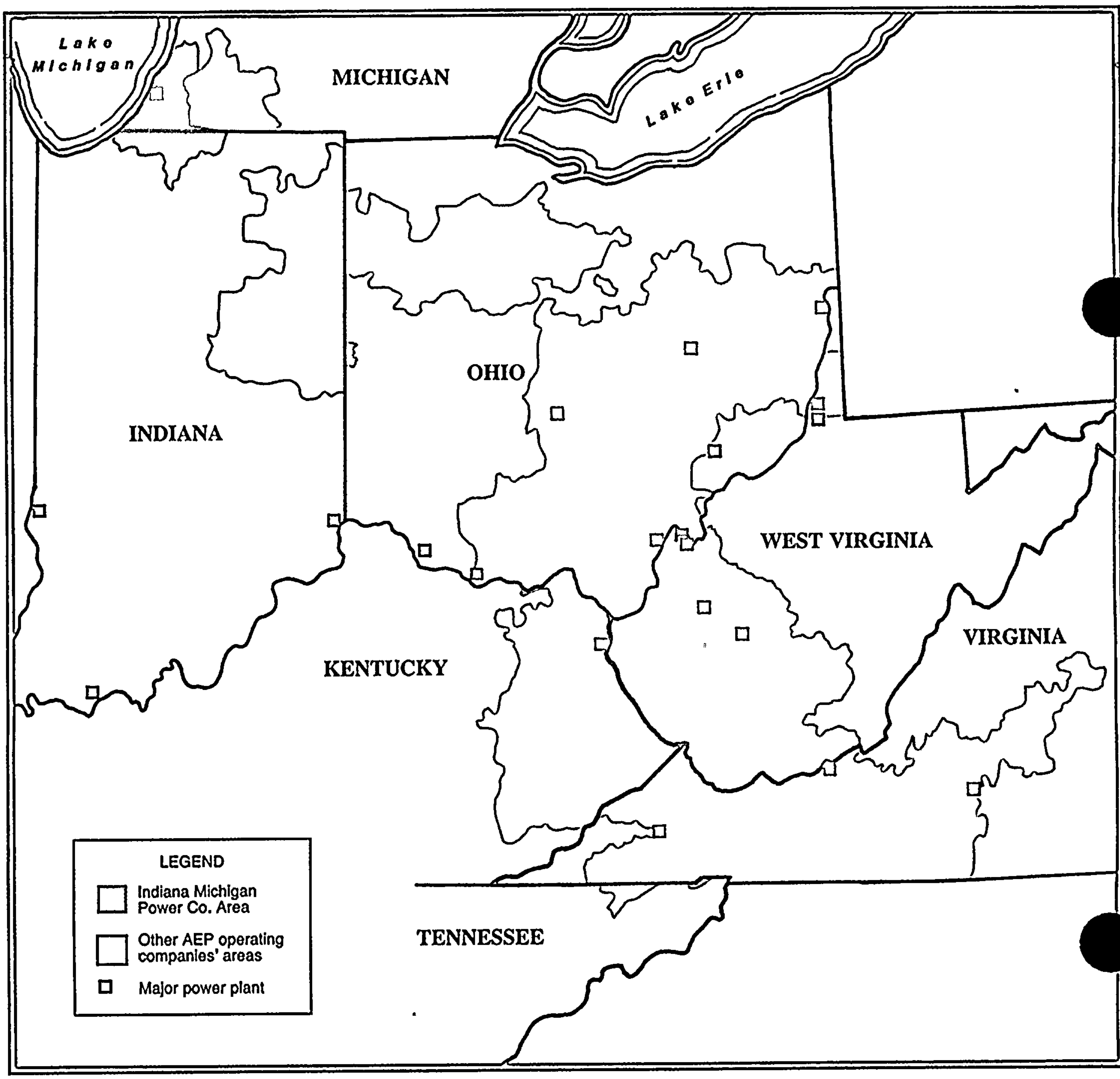
Mr. G. C. Dean
American Electric Power
Service Corporation
1 Riverside Plaza
Columbus, Ohio 43215

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:0909G

INDIANA MICHIGAN POWER COMPANY'S

PROJECTED CASH FLOW

1991 Internal Cash Flow Projection for Donald C. Cook Nuclear Plant ($ Millions)

	Actual 1990	Projected 1991
Net income after taxes	116.3	123
Less dividends paid	129.2	117
Retained earnings	(12.9)	6
Adjustments:		
Depreciation and amortization	155.7	158
Deferred Federal income taxes and investment tax credits	(17.0)	(6)
AFUDC	(2.7)	(.3)
Total adjustments	136.0	149
Internal cash flow	123.1	155
Average quarterly cash flow	30.8	39
Average cash balances and short-term investments*	28.7	10
Total	59.5	49

*Adjusted to eliminate unusually high level from sale of assets.

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

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