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

INDIANA
MICHIGAN
POWER

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

Donald C. Cook Nuclear Plant Units 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 16, 1993

Dear Dr. Murley:

Enclosure 1 contains the Indiana Michigan Power Company's (I&M) annual report for 1992. Enclosure 2 contains a copy of I&M's projected cash flow for 1993. These reports are submitted pursuant to 10 CFR 50.71(b) and 10 CFR 140.21(e).

Sincerely,

E E Fitzpatrick

E. E. Fitzpatrick
Vice President

dgr

Enclosures

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

M004
11

ENCLOSURE 1 TO AEP:NRC:0909I

INDIANA MICHIGAN POWER COMPANY'S

1992 ANNUAL REPORT

Indiana Michigan Power Company

1992 Annual Report

AMERICAN
ELECTRIC
POWER

Contents

Company Background

INDIANA MICHIGAN POWER COMPANY (the Company), a subsidiary of American Electric Power Company, Inc. (AEP), is engaged in the generation, purchase, transmission, distribution and sale 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.

Effective February 29, 1992, Michigan Power Company, another subsidiary of AEP, was merged into the Company.

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 in Utah. Blackhawk Coal Company currently leases or subleases portions of its coal rights, land and related mining equipment to unaffiliated companies. In addition, the Company has a river transportation division (RTD) that barges coal on the Ohio and Kanawha Rivers to generating plants of the Company and its affiliates. RTD also provides some barging services to unaffiliated companies.

The Company serves approximately 520,000 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, rubber and miscellaneous plastic products and chemicals and allied products. In addition, the Company supplies wholesale electric power to other electric utilities, municipalities and electric cooperatives.

The Company has 4,759 megawatts of generating capacity which comes from two nuclear units, seven coal-fired units, one gas unit and 33 hydro units. 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, 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. The Company also shares in wholesale energy sales made by the Power Pool.

Directors

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

Officers

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

Richard C. Menge
President and Chief Operating Officer

Mark A. Bailey
Vice President

Peter J. DeMaria
Vice President and Treasurer

William N. D'Onofrio
Vice President

A. Joseph Dowd
Vice President

E. Linn Draper, Jr.
Vice President

Eugene E. Fitzpatrick
Vice President

Richard F. Hering
Vice President

William J. Lhota
Vice President

Gerald P. Maloney
Vice President

David H. Williams, Jr. (d)
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, 1993 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, Trenary, and Walters, who were employees of Indiana Michigan Power Company.

(a) Elected December 31, 1992
(b) Elected April 28, 1992
(c) Resigned April 28, 1992
(d) Resigned December 31, 1992

Selected Consolidated Financial Data

	Year Ended December 31,				
	1992	1991	1990	1989	1988
			(in thousands)		
INCOME STATEMENTS DATA:					
Operating Revenues	$1,196,755	$1,225,867	$1,271,514	$1,135,587	$1,066,659
Operating Expenses	1,001,235	998,578	1,070,023	921,604	848,915
Operating Income	195,520	227,289	201,491	213,983	217,744
Nonoperating Income (Loss)	14,115	(3,721)	7,557	32,737	43,473
Income Before Interest Charges	209,635	223,568	209,048	246,720	261,217
Interest Charges	85,687	86,636	90,657	107,483	108,320
Net Income	123,948	136,932	118,391	139,237	152,897
Preferred Stock Dividend Requirements	15,417	15,417	15,587	18,048	18,848
Earnings Applicable to Common Stock	$ 108,531	$ 121,515	$ 102,804	$ 121,189	$ 134,049

	December 31,				
	1992	1991	1990	1989	1988
			(in thousands)		
BALANCE SHEETS DATA:					
Electric Utility Plant	$4,266,480	$4,135,820	$4,066,227	$3,969,602	$4,459,334
Accumulated Depreciation and Amortization	1,631,438	1,521,349	1,421,285	1,309,072	1,233,761
Net Electric Utility Plant	$2,635,042	$2,614,471	$2,644,942	$2,660,530	$3,225,573
Total Assets	$3,612,464	$3,447,430	$3,463,919	$4,085,591	$4,004,016
Common Stock and Paid-in Capital	$ 782,741	$ 782,741	$ 782,741	$ 782,741	$ 846,895
Retained Earnings	171,309	169,243	150,408	162,213	165,226
Total Common Shareowner's Equity	$ 954,050	$ 951,984	$ 933,149	$ 944,954	$1,012,121
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
Total	$ 197,000	$ 197,000	$ 197,000	$ 215,030	$ 222,030
Long-term Debt (a)	$1,211,623	$1,130,709	$1,133,833	$1,532,736	$1,585,220
Obligations Under Capital Leases (a)	$ 126,689	$ 102,985	$ 133,447	$ 123,361	$ 168,196
Total Capitalization and Liabilities	$3,612,464	$3,447,430	$3,463,919	$4,085,591	$4,004,016

(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 declined 9.5% to $124 million in 1992 after increasing 16% in 1991 to $137 million. The decrease in 1992 was primarily due to reduced availability of the nuclear units and reduced demand for wholesale energy, partly offset by increased nonoperating income for nonrecurring items. Both nuclear units were out of service for scheduled refueling and one unit experienced an extended, unscheduled, non-refueling related outage. The increase in 1991 net income reflected reductions in fuel expense, energy purchases and maintenance costs, as neither of the Donald C. Cook Nuclear Plant (Cook Nuclear Plant) units were refueled during 1991, and decreased interest charges.

Outlook

The Company, as a member of the AEP System, is entering a new era in the electric utility industry and in the conduct of its business. For the first time in over 50 years, the AEP System is not constructing any new generating capacity. In addition, management is currently in the process of downsizing certain of the System's operations including the American Electric Power Service Corporation (AEPSC). AEPSC provides services at cost to the AEP operating companies including the Company. A reduction in AEPSC costs should reduce the cost of services provided to the Company. The electric utility industry is expected to experience significant changes as a result of the National Energy Policy Act of 1992 (Energy Act) which eases restrictions on independent power producers and allows the Federal Energy Regulatory Commission (FERC) to mandate transmission access with the goal of increasing competition in the generation of electricity and the supply of bulk power to major wholesale customers.

The many strengths of the AEP System should allow Indiana Michigan Power Company (I&M) to compete vigorously in this new environment. The generating capacity of the AEP System is expected to be adequate to the end of the century, postponing the need to embark on an expensive construction program to build new generation. Generating plants—built at low cost, operated efficiently and well maintained—make the AEP System a low-cost producer of energy. To maintain our competitive advantage, management has undertaken efforts that focus on reducing the work force by improving productivity and eliminating duplicative or unnecessary work.

One such effort involves a planning and scheduling program being implemented in the transmission and distribution (T&D) line functions. This program, designed to increase productivity, adopts the latest planning, scheduling and time management techniques and increases management skills of T&D supervisors. The program is expected to enable the Company to maintain its facilities with fewer T&D personnel in the future.

Management is committed to cost-effective Demand Side Management (DSM), conservation and other efforts to delay the addition of new, higher cost generation and transmission facilities. For many years I&M has encouraged the efficient use of electricity through promotion of energy efficient electric equipment such as the heat pump, geothermal electric heating systems, and off-peak thermal storage heating and hot water appliances. The Company is financing and participating in efforts to develop the TranstexT® Advanced Energy Management System which allows residential customers to modify their energy usage according to time-of-day pricing.

In addition to meeting the challenge of competition in the generation of electricity and its sale to wholesale customers, I&M faces many challenges that could adversely affect financial performance and its ability to meet financial obligations and commitments. While management believes the Company is equipped to meet the challenges, uncertainties that could adversely affect future financial performance include the ability to recover cost of service on a timely basis, especially:

- the cost of compliance with the Clean Air Act Amendments of 1990 and other environmental costs under present and future laws and regulations; and
- the full cost of decommissioning its two nuclear generating units and the disposal of spent nuclear fuel.

Management will be facing the possibility of new federal taxes. The Clinton Administration has proposed an energy tax and an increase in the corporate income tax rate as a means of curbing the federal deficit. Others have proposed a tax on carbon dioxide emissions and other actions to reduce "greenhouse" gases and address the as of yet unproven "global warming" problem. These proposals, if enacted, could have an adverse effect on the economy of the service area and financial performance.

Future results of operations depend on the economic health of the service territory, weather patterns and the ability of the American Electric Power System Power Pool (Power Pool) to make wholesale energy sales which are dependent on the weather and the supply and demand for wholesale bulk energy. While many of these items are not generally within management's control, every effort will be made to protect the economy of the Company's service territory from unnecessary and unwise new tax and environmental laws and regulations, to market available capacity and to continue to control operating costs.

Operating Revenues and Energy Sales Decline

Operating revenues declined $29 million in 1992 following a decline of $46 million in 1991. The 1992 decline was attributable to the Cook Nuclear Plant outages which reduced the amount of energy available for sale to the Power Pool coupled with reduced wholesale sales by the Power Pool. The decline in 1991 revenues was due to price competition in the wholesale energy market and a decline in wholesale Power Pool sales to unaffiliated utilities which began in the fourth quarter of 1990.

The reductions in revenues are analyzed as follows:

(dollars in millions)	Increase (Decrease) From Previous Year 1992 Amount	1992 %	1991 Amount	1991 %
Retail:				
Price variance	$ 42.3		$ (0.9)	
Volume variance	3.0		27.6	
	45.3	5.9	26.7	3.6
Wholesale:				
Price variance	75.2		(55.1)	
Volume variance	(141.9)		(26.9)	
	(66.7)	(15.3)	(82.0)	(15.8)
Other Operating Revenues	(7.7)		9.7	
Total	$ (29.1)	(2.4)	$(45.6)	(3.6)

The substantial retail and wholesale price variances in 1992 resulted from the operation of fuel adjustment clauses. Under the retail jurisdictional fuel clauses revenues were accrued representing future recovery of higher fossil fuel generation costs which were incurred during the Cook Nuclear Plant outages.

The 1992 increase in retail sales volume reflects growth in industrial sales partially offset by the effects of mild summer weather on residential service. The substantial decrease in wholesale volume in 1992 was caused by lower sales to the Power Pool due to the Cook Nuclear Plant outages and reduced wholesale sales by the Power Pool. The decline in the wholesale Power Pool sales in 1992 reflected mild weather and price competition in the wholesale market.

The increase in 1991 retail sales volume reflected warmer spring and summer weather partly offset by the transfer of a major industrial customer to a local distribution utility which the Company serves at wholesale. The decline in wholesale volume in 1991 reflected a substantial decrease in wholesale Power Pool sales offset in part by the above noted transfer.

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 an unaffiliated utility under a series of short-term wholesale contracts which expired at the end of 1990. Management has been able to negotiate only a limited number of additional long-term sales, thereby only partially replacing the terminated long-term contract. Efforts to make short-term Power Pool sales have had limited success due to the highly competitive nature of the wholesale market and its dependence on factors not generally within management's control. The level of future wholesale sales will depend on the market price for wholesale power, availability of unaffiliated generating capacity, the economy and weather patterns. Future results of operations will be affected by the ability to make wholesale sales at a profit or, if such sales are not forthcoming, the Company's ability to raise retail rates.

Operating Expenses Increase

Operating expenses increased marginally in 1992 even though generation declined due predominantly to the refueling outages at the Cook Nuclear Plant. In 1991 operating expenses declined nearly 7% due to reduced fuel expense, energy purchases and maintenance expenses reflecting the continued service of both nuclear units during the year after scheduled refueling outages at both units in 1990. Changes in the components of operating expenses were as follows:

(dollars in millions)	Increase (Decrease) From Previous Year 1992 Amount	1992 %	1991 Amount	1991 %
Fuel	$(57.5)	(22.9)	$(25.4)	(9.2)
Purchased Power	57.8	47.1	(40.1)	(24.7)
Other Operation	17.8	7.2	(1.9)	(0.8)
Maintenance	52.9	44.4	(17.8)	(13.0)
Depreciation and Amortization	1.1	0.8	1.2	0.9
Deferred Operating Costs (net)	(47.9)	N.M.	—	—
Taxes Other Than Federal Income Taxes	(0.6)	(0.9)	7.1	12.7
Federal Income Taxes	(20.9)	(45.1)	5.5	13.4
Total	$ 2.7	0.3	$(71.4)	(6.7)

N.M. — Not Meaningful

The Cook Nuclear Plant outages reduced nuclear generation for 1992 by 59% contributing to a 35% overall decline in generation compared with the prior year. The reduction coupled with a 4% lower average cost of fossil fuel caused fuel expense to decline significantly in 1992. The reduction in fuel expense in 1991 occurred, even though generation increased by 8%, because of availability of the nuclear units with their lower fuel cost.

The increase in purchased power expense in 1992 reflects the increase in energy received from the Power Pool because of the Cook Nuclear Plant outages. The decrease in 1991 reflected the decline in wholesale power demand discussed above.

Certain operations and maintenance procedures are performed only when a nuclear unit is out of service. The significant increases in other operation and maintenance expenses are predominantly attributable to the refueling and unscheduled non-refueling outages at Cook Nuclear Plant. However, the impact on earnings from refueling outages was mitigated through the implementation of levelized accounting in January 1992. Levelized accounting spreads the incremental costs of refueling over the time the unit burns the fuel so that an average number of refuelings are reflected in each year's expense. The Company received regulatory approval to defer incremental nuclear refueling outage costs and to amortize them from the start of an outage until the beginning of the next outage. Although the earnings impact of refueling outages are levelized, large fluctuations still appear in the other operation and maintenance expense income statement lines since the deferral is included in "Deferred Operating Costs" on the Consolidated Statements of Income. At December 31, 1992, the Company had deferred $47.2 million of incremental refueling outage costs net of amortization. Amortization of these costs will occur in 1993 and part of 1994.

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 an AEP System transmission equalization agreement.

The decrease in federal income taxes attributable to operations in 1992 was primarily due to the decrease in pre-tax operating book income. In 1991 an increase in pre-tax book income was the principal reason for the increase in federal income taxes.

Nonoperating Income and Interest Charges

Nonoperating income rose significantly in 1992 mainly due to interest income recorded on tax refunds receivable from the Internal Revenue Service in connection with the settlement of audits of prior years' tax returns. Further contributing to the 1992 increase was the partial reversal of a provision recorded in 1991 for a royalty dispute with the state of Utah concerning prior coal-mining operations. The 1991 decline in nonoperating income reflected the above provision and the write-off of the costs associated with an expired federal coal lease of a currently inactive mining subsidiary.

Interest expense declined slightly even though the Company issued an additional $80 million of long-term debt during 1992 as the interest on the new debt was offset by the refinancing of higher cost installment purchase contracts (IPC) and lower interest rates on a variable rate IPC. The decline in interest expense in 1991 was due to the retirement of debt in February 1990 with proceeds from the sale of Rockport Plant Unit 2 (Rockport 2), the refinancing of IPCs at lower rates and a lower average interest rate on a variable rate IPC.

Liquidity and Capital Resources

Construction Spending

Gross plant and property additions were $176 million in 1992 and $149 million in 1991. The increase was due to the acquisition of nuclear fuel in connection with the Cook Nuclear Plant refueling. Construction expenditures for the next three years are estimated at $458 million. The funds for construction of new facilities and improvement of existing facilities come from a combination of internally generated funds, short-term and long-term borrowings and investments in common equity by the Company's parent, AEP. All of the construction expenditures for the next three years 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. At December 31, 1992, unused short-term lines of credit of $521 million shared with other AEP System companies were available. A charter provision limits short-term borrowings to $141 million. Periodically, outstanding short-term debt is reduced through the issuance of long-term debt and preferred stock securities and investments in its common equity by AEP.

The Company is restricted, by the terms of its mortgage and preferred stock, from issuing additional long-term debt or preferred stock unless it meets certain earnings tests. Generally, in order to issue long-term debt without refunding an equal amount of existing debt, pre-tax earnings must be equal to at least twice annual interest charges on long-term debt after giving effect to the new debt. To issue additional preferred stock, after-tax gross income must be at least equal to one and one-half times annual interest and preferred dividend requirements after giving effect to the new preferred stock. Consequently, earnings performance determines the ability to finance. At December 31, 1992, long-term debt and preferred stock coverage ratios were 3.55 and 2.06, respectively.

Concerns and Contingencies

Environmental Costs — Clean Air Act Amendments of 1990

The Clean Air Act Amendments of 1990 require, among other things, substantial reductions in sulfur dioxide and nitrogen oxide emissions from electric generating plants. The law establishes a strict timetable for compliance, with Phase I reductions to be accomplished by 1995 and Phase II reductions to be achieved by the year 2000.

The Company plans to fuel switch at its Tanners Creek Unit 4 to meet Phase I requirements and has announced the retirement of the Breed Plant no later than the end of 1994. Additional costs will be incurred to comply with Phase II requirements at the AEP System's coal-fired generating plants. Should the Company be unable to recover its share of the AEP System compliance costs, it would have an adverse impact on results of operations and financial condition.

Hazardous Material

By-products from generation of electricity include a number of non-hazardous and hazardous materials such as ash, slag, sludge, low level radioactive waste and spent nuclear fuel. In addition, the Company's generating plants and transmission and distribution facilities have used asbestos, polychlorinated biphenyls (PCBs) and other hazardous materials. Significant costs are incurred for the handling, transportation, storage and disposal of hazardous and non-hazardous materials. Additional costs to comply with new laws and regulations if and when enacted could be incurred.

The Superfund created by the Comprehensive Environmental Response Compensation and Liability Act (CERCLA) addresses cleanup of hazardous waste disposal sites and authorizes the EPA to administer the clean-up programs. The Company has been named by EPA as a "potentially responsible party" (PRP) for six sites and has received information requests for three other sites. The Company has also been identified as a PRP under Illinois law for one additional site. For two of the PRP sites liability has been settled with little impact on results of operations. The Company and several unaffiliated companies have been named as defendants in two separate cost recovery lawsuits by unaffiliated parties who are completing remediation activities at two CERCLA sites. 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 received.

Allegations of disposal of hazardous substances are often unsubstantiated. Quantities of material disposed of were generally minor and/or non-hazardous. Typically, the Company is one of many parties named as PRPs for a site and, although liability is joint and several, at least several other parties are generally financially sound enterprises. Therefore, present estimates do not anticipate material clean up costs. However, if for reasons presently unknown, material costs are incurred for clean up, results of operations and financial condition would be adversely impacted unless the costs can be recovered from insurance carriers and/or customers.

The Company maintains insurance against damage and liability from its Cook Nuclear Plant. In the event of a nuclear incident at the Cook Nuclear Plant or any nuclear plant in the United States, the insurance program would require payment of significant retrospective premiums and could involve additional uninsured costs. Unless costs incurred in connection with a nuclear incident are recovered from insurance carriers and/or customers, results of operations and financial condition would be adversely impacted.

Cook Nuclear Plant decommissioning obligations are significant. A decommissioning provision is recorded commensurate with recovery through rates. Regulators have authorized recovery of nuclear decommissioning costs over the life of Cook Nuclear Plant based on an independent 1989 study which estimated decommissioning costs at between $330 million and $369 million. A new study performed in 1991 estimated the cost of decommissioning to range from $588 million to $1,102 million. The substantial increase is primarily due to the anticipated need to store spent nuclear fuel at the plant site for an extended period of time after the plant ceases operation, delaying the commencement of dismantling activities. A request to increase the recovery of decommissioning costs is pending in the Indiana jurisdiction and management plans to seek similar increases in the Michigan and FERC jurisdictions. Management periodically reevaluates decommissioning costs and seeks regulatory approval to recover such amounts as necessary. Failure to fully recover decommissioning costs would adversely affect results of operations and possibly financial condition.

In October 1992 the Energy Act was signed into law. The Energy Act contains a provision to fund the decommissioning and decontamination of U.S. Department of Energy's (DOE) existing uranium enrichment facilities from a combination of sources including assessments against electric utilities which purchased nuclear fuel enrichment services from DOE facilities. The Company will be assessed approximately $48 million subject to inflation adjustments under the law payable annually over 15 years. This amount was recorded as a deferred charge concurrent with the recording of the liability. The first year estimated assessment of $3.25 million will be recognized as a fuel expense in 1993, and, under the provisions of the Energy Act, recovery will be sought in the next fuel rate adjustment proceedings.

Low Level Radioactive Waste Disposal

A federal law established regional compacts which states can enter to provide for the disposal of low level radioactive waste. The state of Michigan, where the Cook Nuclear Plant is located, lost its membership in the Midwest Compact for failure to meet host state obligations. As a result, the Cook Nuclear Plant has been denied access since late 1990 to currently operating low level radioactive waste disposal sites and its low level radioactive waste is being stored at the plant site. The on-site storage facility is expected to provide ample temporary storage space until the year 2002. The Company is unable to estimate what additional costs, if any, it may incur as a result of the revocation of Michigan's membership in the Midwest Compact.

Other New Environmental and Health Concerns

The United States has signed and ratified a United Nations treaty that will require, when effective, the United States to commit to a process of achieving the aim of reducing the emission of greenhouse gases, including carbon dioxide. The U.S. Government has released for public comment a draft of such a plan which emphasizes reductions in the use of fossil fuel, the largest source of carbon dioxide. One option for discouraging carbon dioxide emissions is a carbon or energy tax. Any restriction on carbon dioxide emissions, whether by regulation, taxation or other means, would adversely affect results of operations and financial condition unless the resultant cost can be recovered from customers. In addition, any program to control carbon dioxide emissions would probably impose substantial costs on industrial customers.

In recent years there has been considerable discussion of 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 evidence. The Company continues to work to support efforts to properly study EMF so as 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 EMF, results of operations and financial condition would be adversely affected unless the cost of compliance can be recovered from customers.

Regulatory Matters

In April 1992 a request for an increase of $44.8 million in annual rates was filed with the Indiana Utility Regulatory Commission (IURC) to recover increased operating costs. In September 1992 the Office of Utility Consumer Counselor (UCC) and other intervening parties filed testimony and exhibits opposing the Company's rate increase. The UCC recommended a rate decrease. The IURC has concluded hearings and a rate order is expected in 1993. A significant portion of the difference between the Company's request and the UCC's recommended decrease is related to depreciation rates. If the IURC were to adopt the depreciation rates proposed by the UCC, there would be no immediate effect on earnings but cash flow would be reduced. Unless the Company receives adequate and timely rate relief, results of operations and financial condition would be adversely affected.

As previously discussed and as described in Note 1 of the Notes to Consolidated Financial Statements, the Company practices levelized accounting for incremental nuclear refueling outage costs. The Company is currently requesting recovery of a levelized amount of such costs associated with nuclear refueling outages in its Indiana rate filing discussed above and will request recovery in its next Michigan and FERC base rate filings.

A FERC administrative law judge (ALJ) issued an initial decision in June 1990 regarding a complaint filed by a wholesale customer concerning the reasonableness of the cost of coal acquired from an unaffiliated supplier who leased the Company's western low sulfur coal-mining properties and the coal transportation charges of affiliates. The initial decision would have required the Company to refund to wholesale customers $25 million related to the unaffiliated coal costs and an undetermined amount for affiliated transportation charges. In February 1993 the FERC reversed the ALJ's decision and dismissed the complaint.

Outage at Nuclear Unit

The Company experienced an extended, unscheduled, non-refueling related outage at Cook Nuclear Plant Unit 2 resulting in additional replacement power costs. Under its fuel recovery mechanisms, $38 million of fuel revenues were accrued through December 1992 related to the incremental purchased power costs and other replacement power costs incurred during refueling outages of both nuclear units. In the Indiana jurisdiction the accrued revenues are being collected during the first six months of 1993. Recovery in the Michigan jurisdiction will be sought in the next power supply recovery proceeding.

Merger

Michigan Power Company (MPCo) was merged into the Company on February 29, 1992 after receiving all required regulatory approvals. The merger was accounted for as a pooling-of-interests and did not significantly impact results of operations or financial condition. Pertinent financial information for the Company and MPCo before the merger is shown in Note 1 of the Notes to Consolidated Financial Statements.

Effects of Inflation

Inflation affects the cost of replacing utility plant as well as the cost of operating and maintaining such plant. The rate-making process generally limits recovery to the historical cost of assets resulting in economic losses when inflation effects are not recovered from customers on a timely basis. 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 (FASB) has issued three new accounting standards which affect the Company. Statement of Financial Accounting Standards No. 109 *Accounting for Income Taxes,* (SFAS 109) requires the liability method of accounting for income taxes effective January 1, 1993. In 1993 under SFAS 109 the Company recorded approximately $260 million of net additional deferred income tax liabilities on temporary differences previously flowed through and adjusted previously recorded deferred taxes to the level required at the current statutory tax rate. A corresponding net regulatory asset of $254 million was recorded for the portion of the additional deferred taxes which are recoverable from customers. The new standard was implemented in January 1993 on a prospective basis with only a minor adverse effect on results of operations. As permitted by SFAS 109 the 1992 financial statements do not reflect the implementation of SFAS 109.

SFAS 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions,* required the Company to change its accounting for post-retirement benefits other than pensions from a pay-as-you-go method to an accrual method effective January 1, 1993. This standard permits recognition of the prior service costs as a transition obligation over 20 years. The expense accrual required by the new standard, including recordation over 20 years of the Company's $83 million transition obligation, is expected to be $12.3 million for 1993 versus $4.4 million on the prior pay-as-you-go method. Regulatory commission approval was received in the Michigan and FERC jurisdictions to defer, under the provisions of SFAS 71, any increased costs for which recovery is not provided currently. The Company plans to seek recovery of the increased expense and related deferrals in its next base rate filings. The current Indiana rate filing seeks recovery of incremental SFAS 106 accruals. Should recovery of the SFAS 106 accruals be ultimately denied and rate-making remain on a pay-as-you-go basis, results of operations and possibly financial condition would be adversely impacted.

Another new FASB standard, SFAS 112, *Employers' Accounting for Post-employment Benefits,* will require, beginning in 1994, the accrual of the cost of benefits provided to former or inactive employees who are not retired. SFAS 112 is not expected to have a significant effect on financial condition.

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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, 1992 and 1991, and the related consolidated statements of income, retained earnings, and cash flows for each of the three years in the period ended December 31, 1992. 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, 1992 and 1991, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1992 in conformity with generally accepted accounting principles.

Deloitte & Touche

February 23, 1993

DeloitteTouche
Tohmatsu
International

Consolidated Statements of Income

	Year Ended December 31,		
	1992	1991	1990
		(in thousands)	
OPERATING REVENUES	**$1,196,755**	$1,225,867	$1,271,514
OPERATING EXPENSES:			
Fuel	**193,830**	251,325	276,719
Purchased Power	**180,365**	122,573	162,676
Other Operation	**264,737**	246,935	248,806
Maintenance	**172,147**	119,242	137,022
Depreciation and Amortization	**133,365**	132,285	131,107
Deferred Operating Costs (net of amortization)	**(30,897)**	16,961	16,961
Taxes Other Than Federal Income Taxes	**62,189**	62,783	55,732
Federal Income Taxes	**25,499**	46,474	41,000
Total Operating Expenses	**1,001,235**	998,578	1,070,023
OPERATING INCOME	**195,520**	227,289	201,491
NONOPERATING INCOME (LOSS)	**14,115**	(3,721)	7,557
INCOME BEFORE INTEREST CHARGES	**209,635**	223,568	209,048
INTEREST CHARGES	**85,687**	86,636	90,657
NET INCOME	**123,948**	136,932	118,391
PREFERRED STOCK DIVIDEND REQUIREMENTS	**15,417**	15,417	15,587
EARNINGS APPLICABLE TO COMMON STOCK	**$ 108,531**	$ 121,515	$ 102,804

See Notes to Consolidated Financial Statements.

Consolidated Balance Sheets

	December 31, 1992	December 31, 1991
	(in thousands)	
ASSETS		
ELECTRIC UTILITY PLANT:		
Production	$2,559,905	$2,528,229
Transmission	829,507	815,742
Distribution	576,309	551,055
General (includes nuclear fuel)	182,414	157,340
Construction Work in Progress	118,345	83,454
Total Electric Utility Plant	4,266,480	4,135,820
Accumulated Depreciation and Amortization	1,631,438	1,521,349
Net Electric Utility Plant	2,635,042	2,614,471
OTHER PROPERTY AND INVESTMENTS	403,111	370,334
CURRENT ASSETS:		
Cash and Cash Equivalents	7,459	12,335
Accounts Receivable:		
Customers	62,325	64,602
Affiliated Companies	41,139	35,894
Miscellaneous	31,536	27,139
Allowance for Uncollectible Accounts	(562)	(629)
Fuel — at average cost	53,210	59,148
Materials and Supplies — at average cost	54,004	49,084
Accrued Utility Revenues	78,555	37,487
Other	11,163	7,953
Total Current Assets	338,829	293,013
DEFERRED CHARGES	235,482	169,612
Total	$3,612,464	$3,447,430

See Notes to Consolidated Financial Statements.

	December 31, 1992	December 31, 1991
	(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	726,157	726,157
Retained Earnings	171,309	169,243
Total Common Shareowner's Equity	954,050	951,984
Cumulative Preferred Stock — Not Subject to Mandatory Redemption	197,000	197,000
Long-term Debt	1,168,721	1,112,209
Total Capitalization	2,319,771	2,261,193
OTHER NONCURRENT LIABILITIES	297,475	221,749
CURRENT LIABILITIES:		
Long-term Debt Due Within One Year	42,902	18,500
Short-term Debt	44,200	50,950
Accounts Payable:		
General	37,214	48,211
Affiliated Companies	12,471	16,562
Taxes Accrued	15,829	11,315
Interest Accrued	22,759	22,788
Obligations Under Capital Leases	32,745	26,672
Other	71,891	64,571
Total Current Liabilities	280,011	259,569
DEFERRED INCOME TAXES	283,543	252,532
DEFERRED INVESTMENT TAX CREDITS	195,043	205,181
DEFERRED GAIN ON SALE AND LEASEBACK — ROCKPORT PLANT UNIT 2	218,754	226,965
DEFERRED CREDITS	17,867	20,241
COMMITMENTS AND CONTINGENCIES (Note 3)		
Total	$3,612,464	$3,447,430

Consolidated Statements of Cash Flows

	Year Ended December 31,		
	1992	1991	1990
		(in thousands)	
OPERATING ACTIVITIES:			
Net Income	$ 123,948	$ 136,932	$ 118,391
Adjustments for Noncash Items:			
Depreciation and Amortization	141,453	141,813	140,763
Deferred Operating Costs (net of amortization)	(30,897)	16,961	16,961
Deferred Federal Income Taxes	29,897	(21,877)	(9,145)
Deferred Investment Tax Credits	(9,673)	(9,188)	(8,444)
Changes in Certain Current Assets and Liabilities:			
Accounts Receivable (net)	(7,432)	(4,389)	25,723
Fuel, Materials and Supplies	1,018	(14,520)	(20,629)
Accrued Utility Revenues	(41,068)	3,816	(2,834)
Accounts Payable	(15,088)	(15,222)	(8,902)
Taxes Accrued	4,514	9,937	(201,492)
Interest Accrued	(29)	871	(14,460)
Other (net)	(16,419)	3,575	(1,665)
Net Cash Flows From Operating Activities	180,224	248,709	34,267
INVESTING ACTIVITIES:			
Construction Expenditures	(125,908)	(122,597)	(107,986)
Proceeds from Sales of Property	903	3,246	6,039
Net Cash Flows Used For Investing Activities	(125,005)	(119,351)	(101,947)
FINANCING ACTIVITIES:			
Issuance of Long-term Debt	271,722	78,634	40,000
Retirement of Cumulative Preferred Stock	—	—	(19,048)
Retirement of Long-term Debt	(203,185)	(92,623)	(451,770)
Change in Short-term Debt (net)	(6,750)	12,055	36,220
Dividends Paid on Common Stock	(106,465)	(102,680)	(114,609)
Dividends Paid on Cumulative Preferred Stock	(15,417)	(15,417)	(16,094)
Net Cash Flows Used For Financing Activities	(60,095)	(120,031)	(525,301)
Net Increase (Decrease) in Cash and Cash Equivalents	(4,876)	9,327	(592,981)
Cash and Cash Equivalents January 1	12,335	3,008	595,989
Cash and Cash Equivalents December 31	$ 7,459	$ 12,335	$ 3,008

See Notes to Consolidated Financial Statements.

Consolidated Statements of Retained Earnings

	Year Ended December 31,		
	1992	1991	1990
		(in thousands)	
Retained Earnings January 1	**$169,243**	$150,408	$162,213
Net Income	**123,948**	136,932	118,391
	293,191	287,340	280,604
Cash Dividends Declared:			
Common Stock	**106,465**	102,680	114,609
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
$2.15 Series	**3,440**	3,440	3,440
$2.25 Series	**3,600**	3,600	3,600
$2.75 Series	**—**	—	122
Total Dividends	**121,882**	118,097	130,196
Retained Earnings December 31	**$171,309**	$169,243	$150,408

See Notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements

1. Significant Accounting Policies:

Organization and Regulation

Indiana Michigan Power Company (the Company or I&M) is a wholly owned subsidiary of American Electric Power Company, Inc. (AEP), a public utility holding company. The Company is engaged in the generation, purchase, transmission and distribution of electric power and is a member of the AEP System with its facilities operated in conjunction with the facilities of other AEP owned utilities as an integrated utility system. The Company's 4,759 megawatts (mw) of generating capacity comes from two nuclear units, seven coal-fired units, one gas unit and 33 hydro units, some of which are jointly owned with an affiliated company.

The Company is subject to the regulation of the Securities and Exchange Commission (SEC) under the Public Utility Holding Company Act of 1935 (1935 Act). Retail rates are regulated by the Indiana Utility Regulatory Commission (IURC) and the Michigan Public Service Commission (MPSC). The Federal Energy Regulatory Commission (FERC) regulates wholesale rates.

The Company has two wholly owned subsidiaries: Blackhawk Coal Company and Price River Coal Company, which were formerly engaged in coal-mining operations. Blackhawk Coal Company currently leases and subleases portions of its coal rights, land and related mining equipment to unaffiliated companies.

Merger

After receiving all applicable regulatory approvals, I&M and Michigan Power Company (MPCo), a wholly owned subsidiary of AEP, merged effective February 29, 1992. The merger was accounted for as a pooling-of-interests. In connection with the merger, the common stock of MPCo was canceled by AEP and the Company did not issue any new common stock. Instead the common equity of MPCo was recorded as additional paid-in capital on the Company's books. The 1992 financial statements reflect the merger as if it had occurred at the beginning of the year. The financial statements for 1991 and 1990 have been restated to be comparative.

The separate companies were both using the FERC Uniform System of Accounts and the same fiscal year prior to the merger. Consequently, no adjustments were made to the Company's net asset balances.

The following table shows the separate information for I&M and MPCo for the two months ended February 29, 1992:

	I&M	MPCo
	(in thousands)	
Operating Revenues	$199,018	$7,719
Net Income	24,484	449

Reconciliation of revenues and net income for the years ended December 31, 1991 and 1990 for the separate companies to the amounts shown herein is as follows:

	1991	1990
	(in thousands)	
Operating Revenues:		
I&M	$1,211,607	$1,257,089
MPCo	46,557	45,655
Intercompany Adjustments	(32,297)	(31,230)
As shown herein	$1,225,867	$1,271,514
Net Income:		
I&M	$ 135,286	$ 116,315
MPCo	1,646	2,076
Intercompany Adjustments	—	—
As shown herein	$ 136,932	$ 118,391

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 financial statements reflect rate-making and contain regulatory assets and liabilities as deferred charges and credits in accordance with Statement of Financial Accounting Standards No. 71, *Accounting for the Effects of Certain Types of Regulation* (SFAS 71). The financial statements conform to the accounting and reporting requirements of the SEC under the Securities Exchange Act of 1934. The Company is also subject to the Uniform System of Accounts prescribed by the FERC and the requirements of the state commissions.

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 FERC Uniform System 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 after compounding on a semi-annual basis were 9.25% in 1992 and 1991 and 10.5% in 1990. AFUDC is recorded on construction expenditures for projects which exceed 30 days in duration. Since there were no significant long-term construction projects, AFUDC was not significant in 1992, 1991 and 1990.

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. Depreciation rates include amounts pertaining to the demolition of non-nuclear plant. The accounting and rate-making treatment afforded nuclear decommissioning costs and nuclear fuel disposal costs are discussed in Note 3.

Depreciation is provided for on a straight-line basis over the estimated useful lives of property and determined largely through the use of composite rates by functional class of property.

Other property and investments are stated at cost.

Levelization of Nuclear Refueling Outage Costs

Effective January 1, 1992, with the approval of its state regulatory commissions and the FERC, the Company began to defer incremental operation and maintenance costs associated with refueling outages at the Donald C. Cook Nuclear Plant (Cook Nuclear Plant) for amortization over the period beginning with the commencement of an outage until the beginning of the next outage. In 1992 $71.8 million of incremental outage costs were deferred, and $24.6 million amortized. The net deferral is included in "Deferred Operating Costs" in the Consolidated Statements of Income.

Cash and Cash Equivalents

Cash, unrestricted special deposits, working funds, and temporary cash investments as defined by the FERC are considered 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 rates. The effect of tax reductions resulting from investment tax credits utilized in prior years' federal income tax returns was deferred and is being amortized over the life of the related plant investment.

Operating Revenues

Revenues are accrued for electric service rendered but unbilled at month-end.

Fuel Costs

Retail jurisdictional fuel costs are billed under fuel recovery mechanisms designed to reflect, in rates, changes in costs of fuel with the approval of state regulatory commissions. Accordingly, revenues are accrued related to unrecovered fuel and replacement power costs during outages. Changes in wholesale jurisdictional fuel costs are not deferred. Instead wholesale fuel costs are generally billed monthly.

Jointly-owned and Leased Facilities

The Company and AEP Generating Company (AEGCo), an affiliate, each own a 50% interest in the 1,300-mw Rockport Plant Unit 1 (Rockport 1) which went into commercial operation on December 10, 1984, and leases a 50% interest in the 1,300-mw Rockport Plant Unit 2 (Rockport 2) which went into commercial operation on December 1, 1989. The leases are accounted for as operating leases. I&M operates the plant and bills AEGCo for its share of operating costs. I&M has contractual commitments to buy all of AEGCo's share of Rockport energy and to pay a demand charge for the right to receive such power. The amount of the demand charge is such that when added to other amounts received by AEGCo, it will enable AEGCo to recover all its operating and other expenses including a FERC-approved rate of return on common equity. At December 31, 1992, I&M's investment in the Rockport Plant was $462 million, net of depreciation.

Other

Gains or losses on reacquired debt that is refinanced are deferred and amortized over the term of the replacement debt in accordance with rate-making treatment. Gains or losses on reacquired debt that is not refinanced are recognized in income in the year of reacquisition in accordance with regulatory approvals.

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 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 are deferred and amortized in accordance with rate-making treatment.

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

2. Rate Matters:

Rate Recovery

In April 1992 testimony and exhibits were filed with the IURC seeking a $44.8 million increase in annual rates to recover increased operating costs. The Office of Utility Consumer Counselor (UCC) recommended in testimony a $30.8 million annual rate decrease. The IURC concluded hearings and is expected to issue a rate order in 1993. A significant portion of the difference between the request and the UCC's recommended decrease is related to depreciation rates. If the IURC were to adopt the depreciation rates proposed by the UCC, there would be no immediate effect on earnings but cash flow would be reduced. Unless the Company receives adequate and timely rate relief, results of operations and possibly financial condition would be negatively impacted.

In June 1992 the FERC issued an order on a November 1989 Initial Decision of a FERC Administrative Law Judge (ALJ) concerning a rate increase for wholesale customers. In 1987 the Company filed for an increase in wholesale rates of $3.1 million. Settlements were reached with three of the five wholesale customer classes in 1988 which the FERC approved. As a result of the June 1992 order, the Company refunded $6.3 million including interest to the two remaining wholesale customers in 1993. The Company had previously provided for the refund.

The FERC order denied recovery from the two wholesale customers of certain Rockport 1 phase-in costs and denied the request to shorten the recovery period of the Rockport 1 rate phase-in plan from 30 years to 10 years. The 10 year recovery period was requested in order to comply with Statement of Financial Accounting Standards No. 92, *Regulated Enterprises — Accounting for Phase-in Plans* (SFAS 92). Since the FERC-approved phase-in plan for the two wholesale customers does not satisfy the requirements of SFAS 92, $7.2 million of costs associated with the Rockport 1 phase-in plan were written off in June 1992. The Company had previously provided for the write-off. Although written off for financial reporting purposes, these costs are expected to be recovered in rates and recognized as revenues over the remaining life of the FERC-approved 30-year phase-in plan.

Unaffiliated Coal and Affiliated Transportation Cost Recovery

A FERC ALJ issued an initial decision in 1990 regarding a complaint filed by a wholesale customer concerning the reasonableness of coal costs from an unaffiliated supplier who leased a Utah mining operation from the Company in 1986 and the coal transportation charges of affiliates. The initial decision would have required refunds to wholesale customers of $25 million related to coal costs and an undetermined amount for affiliated transportation charges. In February 1993 the FERC reversed the ALJ's decision and dismissed the complaint.

Rockport 1 Phase-in Plan

Under phase-in plans that comply with the requirements of SFAS 92, deferrals made during the first three years of operation of Rockport 1 are being recovered and amortized on a straight-line basis through 1997. At December 31, 1992 and 1991, the unamortized deferred returns were $58 million and $76 million, respectively, and unamortized deferred depreciation were $17 million and $22 million, respectively. The Company amortized and recovered $16 million in 1992 and $17 million in 1991 and 1990 which are included in "Deferred Operating Costs" in the Consolidated Statements of Income.

Nuclear Unit Outage Cost Recovery

Cook Plant Unit 2 experienced an extended, unscheduled, non-nuclear related outage beginning in July 1992 which resulted in additional costs for replacement power. The unit returned to service in December. Under the fuel recovery mechanism, incremental purchased power costs which, along with other replacement power costs incurred during refueling outages of both nuclear units, resulted in the accrual of unrecovered fuel revenues of $38 million through December 31, 1992. In Indiana the accrued revenues are being collected during the first six months of 1993. Recovery in Michigan will be sought in the next power supply recovery proceeding.

3. Commitments and Contingencies:

Construction

Construction expenditures for the years 1993-1995 are estimated at $458 million and, in connection with the construction program, commitments have been made.

Unit Power Agreements

The Company is committed under unit power agreements to purchase 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 fuel clause mechanisms generally provide for recovery of changes in fuel cost. The contracts are for various terms, the longest of which extends to the year 2014, and contain clauses that would release the Company from its obligation under certain conditions.

Litigation

In November 1992 the DeKalb County Circuit Court of Indiana dismissed the case of a local distribution utility against the Company. The case was filed 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 service in the designated service territory of another utility. The Company had received approximately $29 million in gross revenues from a major industrial customer in the local distribution utility's service territory. The case resulted from a Supreme Court of Indiana decision which overruled an appeals court and voided an IURC order which assigned the major industrial customer to the Company. The local distribution utility has begun to appeal this case.

The Company is involved in other legal proceedings. 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 financial condition.

Environmental Matters — Clean Air

The Clean Air Act Amendments of 1990 (CAAA) require, among other things, significant reductions in sulfur dioxide and nitrogen oxide emissions from various existing AEP System generating plants. The law established a deadline of 1995 for Phase I reductions and 2000 for Phase II reductions as well as a permanent nationwide cap on sulfur dioxide emissions after 1999.

The AEP Systemwide compliance plan calls for fuel switching to medium-sulfur coal at Tanners Creek Unit 4 with no additional capital cost. The Breed unit which is a Phase I affected unit is expected to be retired prior to the January 1, 1995 effective date of the CAAA. The Company's other generating units are not affected in Phase I.

The Company will incur additional costs to comply with Phase II requirements at its generating plants and those of affiliated AEP System Power Pool members. If unable to recover compliance costs from its customers, results of operations and financial condition would be adversely impacted.

Other 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 (PCBs) and other hazardous materials have been used in the generating plants and transmission/distribution facilities. Substantial costs are incurred 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 United States signed and ratified a United Nations treaty that, when effective, would require the United States to commit to a process of achieving the aim of reducing the emission of "greenhouse" gases, including carbon dioxide. The U.S. Government released for public comment a draft of the national action plan for achieving this aim, which emphasizes reductions in the use of fossil fuel, the largest source of carbon dioxide, through voluntary energy efficiency programs and some regulatory controls, particularly on the electric utility industry. One option for controlling carbon dioxide emissions is a carbon or energy tax. The Clinton Administration has proposed an energy tax based on the heat content of all fuels including coal. Such new tax could negatively impact the economy of the service area and sales of energy.

The Company intends to seek recovery of all environmental costs incurred in the generation, transmission and distribution of electric energy for the benefit of its customers. If not recovered from customers, new environmental costs including any related new taxes would adversely affect results of operations and financial condition.

Nuclear Insurance

The Price-Anderson Act limits public liability for a nuclear incident at any nuclear plant in the United States to $7.8 billion. The Company has insurance coverage for liability from a nuclear incident at its Cook Nuclear Plant. Such coverage is provided through a combination of private liability insurance, with the maximum amount available of $200 million, and mandatory participation, for the remainder of the $7.8 billion liability, in an industry retrospective deferred premium plan which would in case of a nuclear incident assess all licensees of nuclear plants in the United States. Under the deferred premium plan the Company could be assessed up to $132 million payable in annual installments of $20 million in the event of a nuclear incident at Cook or any plant in the United States. There is no limit on the number of incidents for which the Company could be assessed.

The Company also has property damage, decontamination and decommissioning insurance in the amount of $2.625 billion. Nuclear insurance pools provide $1.3 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 $9.9 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 $2.425 billion less any amounts used for stabilization and decontamination. As provided by NEIL the remaining $200 million (less any stabilization and decontamination expenditures over $2.425 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 and third years, 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 Nuclear Plant and other costs in the event of a nuclear incident at the Cook Nuclear Plant. Future losses or liabilities which are not completely insured, unless recovered through rates, would have a material adverse effect on results of operations and financial condition.

Disposal of Spent Nuclear Fuel

The Nuclear Waste Policy Act of 1982 established federal responsibility for the permanent off-site disposal of spent nuclear fuel and assessed 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 from its Cook Nuclear Plant. Under the terms of the contract the Company pays a fee of one mill per kwh for fuel consumed after April 6, 1983. The fee is being collected from customers and remitted to the U.S. Treasury. A fee of $72 million (plus interest of $71 million to December 31, 1992) for disposal of fuel consumed prior to April 7, 1983 has been recorded as other long-term debt and deferred until recovered from customers. The amount deferred ($25.6 million as of December 31, 1992) is being amortized on a basis commensurate with recovery from customers. 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 customers are deposited in external funds until used to pay disposal fees.

Nuclear Decommissioning

An independent consulting firm estimated the cost of decommissioning Cook Nuclear Plant at $330 million to $369 million in 1989 dollars. All rate-making jurisdictions have authorized the recovery of an approved level of decommissioning costs.

In 1991 the consultant's updated study 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 Nuclear Plant would be in the range of $588 million to $1,102 million in 1991 dollars. The substantial increase is due primarily 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 April 1992 Indiana rate increase filing seeks to recover an additional $10 million annually for decommissioning the Cook Nuclear Plant. The Company intends to seek an appropriate increase in its level of collections for decommissioning expense in its other jurisdictions. The Company will continue to periodically reevaluate the cost of decommissioning and to seek increased recovery in rates as necessary.

The Company records decommissioning costs in other operation expense and records a provision for nuclear decommissioning expense in other noncurrent liabilities in amounts equal to the decommissioning costs recovered from customers which was $12 million in 1992, $11 million in 1991 and $10 million in 1990. Funds recovered through the rate-making process for nuclear decommissioning are deposited in external funds for the future payment of decommissioning costs. Trust fund earnings increase the fund balance and the recorded liability, thus reducing the amount to be collected from customers.

Energy Policy Act — Nuclear Fees

In October 1992 the National Energy Policy Act of 1992 (Energy Act) was signed into law. The Energy Act contains a provision to fund the decommissioning and decontamination of DOE's existing uranium enrichment facilities from a combination of sources including assessments against electric utilities which purchased enrichment services from DOE facil-

ities. The Company's assessment is estimated to be approximately $48 million subject to inflation adjustments and is payable in annual assessments over 15 years. The assessment was recorded as a deferred charge concurrent with recording of the liability. The first year estimated assessment of $3.25 million will be recognized as a fuel expense, and, under the provisions of the Energy Act, recovery will be sought in the next fuel rate adjustment proceedings.

4. Common Shareowner's Equity:

Except for the effect of the merger of MPCo discussed in Note 1, there were no transactions affecting the common stock or paid-in capital accounts in 1992, 1991 or 1990.

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 to pay dividends (other than stock dividends) on common stock and for other purposes. At December 31, 1992, approximately $45.9 million of retained earnings were restricted. In addition, regulatory approval is required 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. Power Pool members are compensated for the out-of-pocket costs of energy they deliver to the Power Pool by energy credits. Likewise Power Pool members pay energy charges for the energy they receive.

The Company received credits totaling $154.1 million in 1992, $204.8 million in 1991 and $230.5 million in 1990 from providing capacity and supplying energy to the Power Pool and recorded them as operating revenues. The charges for energy received from the Power Pool were included in purchased power expense and totaled $82.6 million in 1992, $24.6 million in 1991 and $53.9 million in 1990.

As a Power Pool member the Company shares in wholesale sales to unaffiliated utilities made by the Power Pool. The Company's share was included in operating revenues in the amount of $45.8 million in 1992, $65.5 million in 1991 and $126.7 million in 1990.

In addition, the Power Pool purchases power for immediate resale to other unaffiliated utilities. The Company's share of these purchases was included in purchased power expense and totaled $6.5 million in 1992, $13.7 million in 1991 and $28.2 million in 1990. Revenues from these transactions are included in the above Power Pool wholesale sales.

The cost of power purchased from AEGCo, an affiliated company that is not a member of the Power Pool, was included in purchased power expense in the amounts of $88 million, $83 million and $79 million in 1992, 1991 and 1990, 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, credits of $48.2 million, $46.2 million and $47.6 million were recorded in other operation expense for transmission services in 1992, 1991 and 1990, respectively.

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

	Year Ended December 31,		
	1992	1991	1990
		(in thousands)	
Affiliated Companies	$24,753	$23,863	$25,851
Unaffiliated Companies	3,964	4,641	2,882
Total	$28,717	$28,504	$28,733

American Electric Power Service Corporation (AEPSC) provides certain management and professional services to AEP System companies. 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 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 funding policy is to make annual contributions to the plan's trust fund in an amount 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, 1992, 1991 and 1990 were $5.6 million, $2.3 million and $2.8 million, respectively.

In addition to pension benefits, certain other benefits are provided to retired employees under an AEP System other post-retirement benefit plan. Employees become eligible for health care and life insurance benefits if they have 10 years of service at retirement. The cost of such retiree benefits is recognized as an expense when paid and totaled $2.7 million in 1992, $2.6 million in 1991 and $2.8 million in 1990.

The AEP System's pension and other post-retirement 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. The change in the other post-retirement 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 post-retirement benefits unless they retired at age 60 or later.

The Company offers an AEP System 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 annual contributions to the savings plan trust were $3.3 million in 1992, $3.1 million in 1991 and $2.9 million in 1990.

The Financial Accounting Standards Board (FASB) has issued Statement of Financial Accounting Standards No. 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions* (SFAS 106) which requires employers, beginning in 1993, to accrue for the costs of retiree benefits other than pensions. In addition to accruing the current cost, SFAS 106 also requires the recognition of an employer's prior service costs (the unfunded and unrecognized accumulated post-retirement benefit obligation) in the initial year of implementation or as a transition obligation over either the greater of the average remaining service period of employees or 20 years. The Company adopted SFAS 106 in January 1993 and elected the 20-year transition option.

In anticipation of the new accounting requirement, the Company undertook several measures to reduce the impact of adopting the new standard. First, the Company established a Voluntary Employee Beneficiary Association (VEBA) trust fund for post-retirement benefits other than pensions and made a $4.3 million contribution in 1990, the maximum amount deductible for federal income tax purposes. Another measure taken 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 post-retirement 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. The policies generated cash of $1.7 million in 1992 and $700,000 in 1991 inclusive of related tax benefits which was contributed to the VEBA trust fund.

The annual accrued expense required by SFAS 106 for employees and retirees, inclusive of the cost of the changes in the other post-retirement benefit plan and 20-year recordation of an $83 million transition obligation, is expected to be $12.3 million in 1993 versus $4.4 million on the prior pay-as-you-go method. The Company has received authority from the FERC to defer, beginning January 1, 1993, under the provisions of SFAS 71, the increased post-retirement benefit cost which will not be currently recovered in rates after SFAS 106 is implemented. In its Michigan jurisdiction, the Company may defer the SFAS 106 increase in costs for up to three years pending recovery in the next base rate case filing. In the Indiana jurisdiction, the Company has filed for full recovery and expects a decision in 1993. Should recovery of the SFAS 106 accruals and related deferrals be denied, results of operations and possibly 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,		
	1992	1991	1990
		(in thousands)	
Real and Personal Property	$35,818	$33,265	$27,913
State Gross Receipts, Excise, Franchise and Miscellaneous State and Local	15,179	15,902	13,455
State Income	2,281	5,541	6,607
Payroll	8,911	8,075	7,757
Total	$62,189	$62,783	$55,732

The following are the amounts of cash paid for:

	Year Ended December 31,		
	1992	1991	1990
		(in thousands)	
Interest (net of capitalized amounts)	$84,691	$84,581	$103,407
Income Taxes	15,285	73,694	248,338

The amounts of non-cash acquisitions under capital leases were $47,905,000 in 1992, $25,624,000 in 1991 and $57,227,000 in 1990.

8. Federal Income Taxes:

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

	Year Ended December 31, 1992	1991	1990
		(in thousands)	
Charged (Credited) to Operating Expenses (net):			
Current	$ 9,122	$ 73,702	$53,788
Deferred	25,405	(18,793)	(6,871)
Deferred Investment Tax Credits	(9,028)	(8,435)	(5,917)
Total	25,499	46,474	41,000
Charged (Credited) to Nonoperating Income (net):			
Current	1,569	3,348	7,656
Deferred	4,492	(3,084)	(2,274)
Deferred Investment Tax Credits	(645)	(753)	(2,527)
Total	5,416	(489)	2,855
Total Federal Income Taxes as Reported	$30,915	$ 45,985	$43,855

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, 1992	1991	1990
		(in thousands)	
Net Income	$123,948	$136,932	$118,391
Federal Income Taxes	30,915	45,985	43,855
Pre-tax Book Income	$154,863	$182,917	$162,246
Federal Income Taxes on Pre-Tax Book Income at Statutory Rate (34%)	$ 52,653	$ 62,192	$ 55,164
Increase (Decrease) in Federal Income Taxes Resulting From the Following Items:			
Removal Costs	(3,042)	(2,259)	(1,663)
Mine Development and Mineral Rights Amortization	2,129	2,773	4,369
Investment Tax Credits (net)	(9,011)	(9,087)	(11,004)
Corporate Owned Life Insurance	(4,402)	(3,044)	(1,802)
Other	(7,412)	(4,590)	(1,209)
Total Federal Income Taxes as Reported	$ 30,915	$ 45,985	$ 43,855
Effective Federal Income Tax Rate	20.0%	25.1%	27.0%

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

	Year Ended December 31, 1992	1991	1990
		(in thousands)	
Current:			
Federal Income Taxes	$10,029	$76,949	$64,004
Investment Tax Credits	662	101	(2,560)
Total Current Federal Income Taxes	10,691	77,050	61,444
Deferred:			
Depreciation	(8,356)	(6,969)	1,135
Unrecovered and Levelized Fuel	11,729	(670)	4,135
Nuclear Fuel	5,410	(6,484)	384
Unbilled Revenue	(430)	—	(3,878)
Deferred Return — Rockport Plant Unit 1	(2,772)	(2,864)	(2,864)
Deferred Net Gain — Rockport Plant Unit 2	4,230	3,098	3,457
Deferred Nuclear Refueling Costs	16,048	—	—
Accrued Interest Income	3,854	—	—
Other	184	(7,988)	(11,514)
Total Deferred Federal Income Taxes	29,897	(21,877)	(9,145)
Total Deferred Investment Tax Credits	(9,673)	(9,188)	(8,444)
Total Federal Income Taxes as Reported	$30,915	$45,985	$43,855

The Company and its subsidiaries join in the filing of a consolidated federal income tax return with their affiliates in the AEP System. The allocation of the AEP System's current consolidated federal income tax to the System companies is in accordance with SEC rules under the 1935 Act. These rules permit the allocation of the benefit of current tax losses and investment tax credits utilized to the System companies giving rise to them in determining their current tax expense. 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.

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 1988. Returns for the years 1988 through 1990 are being audited by the IRS. In the opinion of management, the final settlement of open years will not have a material effect on earnings.

SFAS 109, *Accounting for Income Taxes,* prescribes, among other things, that the Company change from the deferral to the liability method of accounting for income taxes. The Company adopted SFAS 109 effective January 1, 1993. The adoption of the new standard resulted in an increase in net deferred tax liabilities of approximately $259.6 million to reflect temporary differences previously flowed-through and to adjust existing deferred taxes to the level required at the current statutory tax rate. A net regulatory asset of $254.3 million related to the portion of these additional deferred taxes which are recoverable in rates was also recorded with implementation of SFAS 109. The implementation of the new standard did not significantly impact results of operations. As permitted by SFAS 109, the effects of the implementation of the new standard in January 1993 are not reflected in these financial statements.

9. Leases:

The Company and its subsidiaries lease property, plant and equipment for periods up to 35 years. Most of the leases require the payment of 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 and finances all of its investment in nuclear fuel. The nuclear fuel lease is accounted for as a capital lease.

Rental payments for capital and operating leases are primarily charged to operating expenses in accordance with ratemaking treatment. The rental payments by lease type and component are as follows:

	Year Ended December 31,		
	1992	1991	1990
		(in thousands)	
Operating Leases	$109,466	$101,013	$ 87,505
Capital Leases:			
Amortization of Principal	24,124	54,528	46,933
Interest	7,473	9,907	10,919
Total Rental Payments	$141,063	$165,448	$145,357

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

	December 31, 1992	December 31, 1991
	(in thousands)	
Electric Utility Plant:		
Production	$ 11,407	$ 10,568
Distribution	14,702	14,661
General:		
Nuclear Fuel (net of amortization)	84,208	66,456
Other	46,494	39,242
Total Electric Utility Plant	156,811	130,927
Accumulated Amortization	30,630	28,146
Net Electric Utility Plant	126,181	102,781
Other Property	2,327	1,957
Accumulated Amortization	1,819	1,753
Net Other Property	508	204
Net Properties under Capital Leases	$126,689	$102,985
Obligations under Capital Leases (a)	$126,689	$102,985

(a) Including amounts due within one year.

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

Future minimum lease payments at December 31, 1992, by year and in the aggregate, are as follows:

	Capital Leases	Operating Leases
	(in thousands)	
1993	$ 8,243	$ 99,024
1994	7,128	98,667
1995	6,266	98,191
1996	5,556	97,871
1997	5,021	96,014
Later Years	33,383	2,102,807
Total Future Minimum Lease Payments	65,597	$2,592,574
Less Estimated Interest Element	23,116	
Estimated Present Value of Future Minimum Lease Payments	42,481	
Unamortized Nuclear Fuel	84,208(a)	
Total	$126,689	

(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 $23.0 million, $56.6 million and $50 million were charged to fuel expense in 1992, 1991 and 1990, 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.

10. Cumulative Preferred Stock:

At December 31, 1992, authorized shares of cumulative preferred stock were as follows:

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

In 1990, the Company redeemed 47,325 shares of the 12% series and 531,900 shares of the $2.75 series cumulative preferred stock subject to mandatory redemption. The cumulative preferred stock outstanding at December 31, 1992 is not subject to mandatory redemption and is callable at the Company's option 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 Company issued 300,000 shares of 6⅞% Cumulative Preferred Stock—Subject to Mandatory Redemption, par value $100, on February 17, 1993. The cumulative preferred stock not subject to mandatory redemption is as follows:

Series	Call Price December 31, 1992	Par Value	Shares Outstanding December 31, 1992	Amount December 31, 1992	Amount December 31, 1991
				(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	25.54	25	1,600,000	40,000	40,000
$2.25**	26.13	25	1,600,000	40,000	40,000
				$197,000	$197,000

**Called for redemption on March 1, 1993

11. Long-term Debt and Lines of Credit:

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

	December 31, 1992	December 31, 1991
	(in thousands)	
First Mortgage Bonds	$ 713,916	$ 627,494
Sinking Fund Debentures	6,053	6,053
Notes Payable to Banks	40,000	50,000
Installment Purchase Contracts	308,333	308,971
Other Long-term Debt (a)	143,321	138,191
	1,211,623	1,130,709
Less Portion Due Within One Year	42,902	18,500
Total	$1,168,721	$1,112,209

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

First mortgage bonds outstanding were as follows:

% Rate	Due	December 31, 1992	December 31, 1991
		(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
7.3	1999 — December 15 (a)	35,000	—
8⅞	2000 — April 1	50,000	50,000
7.6	2002 — November 1	50,000	—
7.7	2002 — December 15 (a)	40,000	—
9½	2003 — June 1	—	162,000
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	10,000
9.5	2021 — May 1	10,000	10,000
9.5	2021 — May 1	20,000	20,000
8.75	2022 — May 1	50,000	—
8.5	2022 — December 15 (a)	75,000	—
Unamortized Discount (net)		(3,020)	(1,442)
		713,916	627,494
Less Portion Due Within One Year		42,902	13,500
Total		$671,014	$613,994

(a) Proceeds were deposited with a trustee for the January 1993 retirement, prior to maturity, of the 9½% Series due 2003 at the redemption price of 103.718%.

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, 1992, sufficient principal amounts of debentures had been reacquired in anticipation of all future sinking fund requirements. Additional debentures of up to $300,000 may be called annually.

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

	December 31, 1992	December 31, 1991
	(in thousands)	
11.8% due 1992	$ —	$ 5,000
9.07% due 1995	40,000	40,000
Variable interest rate note due 1996	—	5,000
	40,000	50,000
Less Portion Due Within One Year	—	5,000
Total	$40,000	$45,000

The variable interest rate note payable was issued initially bearing interest at the prime rate and due January 1996. This note was retired during 1992. The interest rate on the note was 6.4% at December 31, 1991.

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

% Rate	Due	December 31, 1992	December 31, 1991
		(in thousands)	
City of Lawrenceburg, Indiana:			
8½	2006 — July 1	$ —	$ 25,000
7	2006 — May 1	40,000	40,000
6⅞	2006 — May 1	12,000	12,000
7	2015 — April 1	25,000	—
City of Rockport, Indiana:			
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	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		(3,667)	(3,029)
Total		$308,333	$308,971

(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 3.7% for 1992 and 4.7% for 1991.

Under the terms of certain installment purchase contracts, the Company is required to pay amounts sufficient to enable the cities to pay interest on and the principal (at stated maturities and upon mandatory redemption) of related pollution control revenue bonds issued to finance the construction of pollution control facilities at certain generating plants. On certain series the principal is payable at stated maturities or on the demand of the bondholders at periodic interest adjustment dates. 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.

At December 31, 1992, annual long-term debt payments, excluding premium or discount, are as follows:

	Principal Amount (in thousands)
1993	$ 42,902
1994	—
1995	140,000
1996	—
1997	125,000
Later Years	910,408
Total	$1,218,310

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 $141 million. The Company shares bank lines of credit with other AEP System companies and at December 31, 1992 and 1991 had unused shared lines of $521 million and $374 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. Outstanding short-term debt consisted of $44.2 million of commercial paper at December 31, 1992 and $14.9 million of notes payable and $36.1 million of commercial paper at December 31, 1991.

12. Disclosures about Fair Value of Financial Instruments

The estimated fair value of financial instruments has been determined using available market information and appropriate valuation methodologies. However, considerable judgment is required in interpreting market data to develop the estimates of fair value. Accordingly, the estimates are not necessarily indicative of the amounts that could be realized in a current market exchange. The fair values do not include early redemption premiums, underwriters' fees and commissions and refunding costs (legal and registration fees). Also, the Company may be prohibited from realizing the estimated fair values due to noncallable provisions.

The fair value estimates are based on pertinent information as of December 31, 1992. Such amounts have not been comprehensively revalued for purposes of these financial statements since December 31, 1992, and estimates of fair value at any subsequent date may differ significantly although management is not aware of any factors that would significantly affect the estimated fair value amounts.

The carrying amount of cash and cash equivalents, accounts receivable, short-term debt and accounts payable shown in the Consolidated Balance Sheet approximates fair value because of the short-term maturities of these instruments.

External trust funds established to accumulate funds collected from customers for future nuclear liabilities discussed in Note 3 are included in Other Property and Investments at original cost. The trust funds are invested primarily in long-term tax-exempt municipal bonds. The fair value of the instruments held in the trust funds approximates carrying value based on estimated market prices for those and similar investments.

Long-term debt is comprised of first mortgage bonds, notes payable to banks, installment purchase contracts, sinking fund debentures and miscellaneous long-term debt instruments. The fair value of long-term debt approximates carrying value based on quoted market prices for the same or similar issues and the current interest rates offered for debt of the same remaining maturities.

13. Unaudited Quarterly Financial Information:

The following consolidated quarterly financial information is unaudited but, in the opinion of management, 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)	
1992			
March 31	$301,134	$54,022	$35,035
June 30	280,421	43,535	24,844
September 30	311,080	45,323	24,384
December 31	304,120	52,640	39,685
1991			
March 31	308,149	61,230	40,366
June 30	292,979	49,295	28,977
September 30	314,881	61,493	35,772
December 31	309,858	55,271	31,817

Fourth quarter 1992 earnings include $13 million comprised of interest on prior years federal income tax refunds and cost reductions due to favorable benefit plan experience.

Operating Statistics

	1992	1991	1990	1989	1988
OPERATING REVENUES (in thousands):					
Retail:					
Residential:					
Without Electric Heating	$ 209,682	$ 206,257	$ 192,822	$ 195,504	$ 202,390
With Electric Heating	98,553	93,289	88,718	95,987	98,784
Total Residential	308,235	299,546	281,540	291,491	301,174
Commercial	228,285	216,303	205,025	205,918	204,229
Industrial	267,643	241,858	244,773	251,279	250,877
Miscellaneous	11,012	12,120	11,799	12,021	12,180
Total Retail	815,175	769,827	743,137	760,709	768,460
Wholesale (sales for resale)	369,379	436,083	518,080	361,962	289,066
Total Revenues from Energy Sales	1,184,554	1,205,910	1,261,217	1,122,671	1,057,526
Provision for Refunds of Revenues Collected in Prior Years	(4,038)	5,176	(5,176)	—	(1,133)
Total Net of Provision for Refunds	1,180,516	1,211,086	1,256,041	1,122,671	1,056,393
Other	16,239	14,781	15,473	12,916	10,266
Total Operating Revenues	$1,196,755	$1,225,867	$1,271,514	$1,135,587	$1,066,659

	1992	1991	1990	1989	1988
SOURCES AND SALES OF ENERGY (in millions of kilowatt-hours):					
Sources:					
Net Generated:					
Fossil Fuel	11,597	12,109	14,451	10,634	8,707
Nuclear Fuel	6,418	15,524	11,115	12,094	9,791
Hydroelectric	100	109	127	108	82
Total Net Generated	18,115	27,742	25,693	22,836	18,580
Purchased and Power Pool	9,342	5,237	7,983	7,630	6,341
Total Sources	27,457	32,979	33,676	30,466	24,921
Less: Losses, Company Use, Etc.	1,466	1,454	1,633	1,647	1,674
Net Sources	25,991	31,525	32,043	28,819	23,247
Sales:					
Retail:					
Residential:					
Without Electric Heating	3,001	3,166	2,955	2,975	3,005
With Electric Heating	1,633	1,625	1,525	1,627	1,611
Total Residential	4,634	4,791	4,480	4,602	4,616
Commercial	3,747	3,726	3,536	3,519	3,431
Industrial	5,685	5,382	5,452	5,512	5,371
Miscellaneous	194	233	229	236	236
Total Retail	14,260	14,132	13,697	13,869	13,654
Wholesale (sales for resale)	11,731	17,393	18,346	14,950	9,593
Total Sales	25,991	31,525	32,043	28,819	23,247

OPERATING STATISTICS (Concluded)

	1992	1991	1990	1989	1988
Average Cost of Fuel Consumed (in cents):					
Per Million Btu:					
Coal	**136**	141	145	164	182
Nuclear	**54**	48	58	61	70
Overall	**103**	84	105	106	120
Per Kilowatt-hour Generated:					
Coal	**1.34**	1.39	1.42	1.62	1.81
Nuclear	**.61**	.53	.64	.67	.77
Overall	**1.08**	.91	1.08	1.11	1.26
Residential Service — Averages:					
Annual Kwh Use per Customer:					
Total	**10,107**	10,539	9,944	10,303	10,449
With Electric Heating	**17,513**	17,703	16,897	18,337	18,438
Annual Electric Bill:					
Total	**$672.31**	$659.01	$624.95	$652.64	$681.72
With Electric Heating	**$1,056.91**	$1,016.24	$983.28	$1,081.78	$1,130.71
Price per Kwh (in cents):					
Total	**6.65**	6.25	6.28	6.33	6.52
With Electric Heating	**6.04**	5.74	5.82	5.90	6.13
Number of Customers:					
Year-End:					
Retail:					
Residential:					
Without Electric Heating	**366,835**	364,154	362,645	360,040	356,755
With Electric Heating	**94,175**	92,657	91,179	89,881	88,366
Total Residential	**461,010**	456,811	453,824	449,921	445,121
Commercial	**52,542**	51,491	50,994	50,043	48,958
Industrial	**5,000**	4,847	4,801	4,792	4,766
Miscellaneous	**1,751**	2,226	2,160	2,168	2,123
Total Retail	**520,303**	515,375	511,779	506,924	500,968
Wholesale (sales for resale)	**53**	53	55	51	109
Total Customers	**520,356**	515,428	511,834	506,975	501,077

Dividends and Price Ranges of Cumulative Preferred Stock

By Quarters (1992 and 1991)

	1992 — Quarters				1991 — 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)	—	—	—	—	—	—	—	—
Bid (high/low)	47/39½	47/47	48/47	50/48	42/39½	42/39½	42¼/39½	44/39½
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	88½	88½	92	92	80⅞	79¾	83	85¼
— Low	83¼	84½	85½	89	71	76¼	76¼	81
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	95¾	96⅛	98¾	98¼	92	87⅜	87	92¾
— Low	90½	92¼	93½	93	83	83¾	83¼	88
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	102¼	102	103	103	94⅜	95	96½	100½
— Low	98½	99	100¼	100	89	92½	91½	95
($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	26	26	27¼	27	25	25⅜	25⅜	26
— Low	25	25	25⅜	25½	23⅛	23½	23½	24½
$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	27¼	27¼	27½	27¼	26	25⅞	26	26¾
— Low	26	25⅞	26	25¾	23⅝	24½	24¼	24

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.

SECURITY OWNER INQUIRIES

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

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

FORM 10-K ANNUAL REPORT

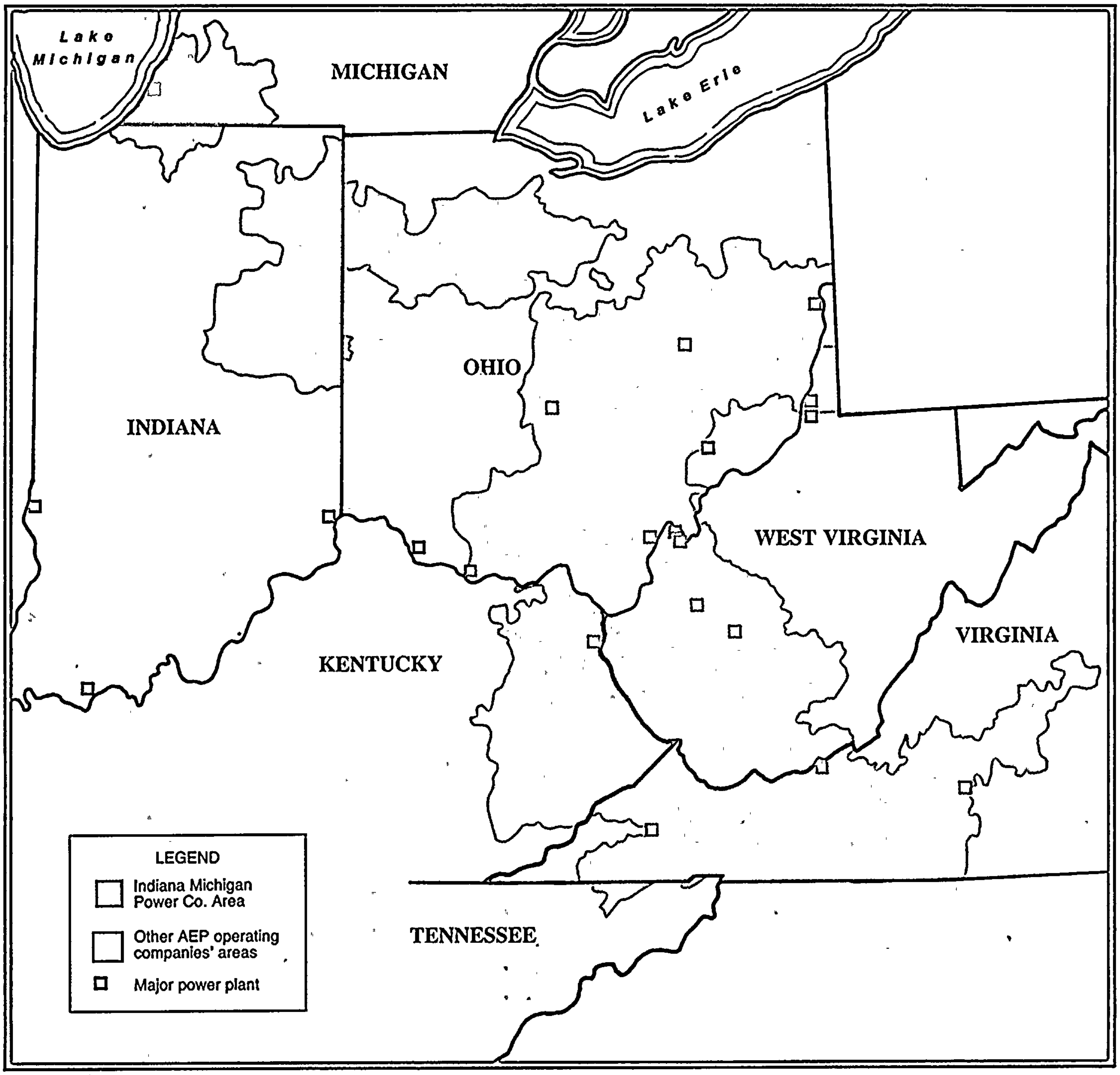
The Company's Annual Report (Form 10-K) to the Securities and Exchange Commission will be available in April 1993 to shareowners and at no cost. Please address such requests to:

Geoffrey C. Dean
American Electric Power Service Corporation
27th Floor
1 Riverside Plaza
Columbus, OH 43215

TRANSFER AGENT AND REGISTRAR OF CUMULATIVE PREFERRED STOCK

First Chicago Trust Company of New York
30 West Broadway
New York, NY 10007

Indiana Michigan Power Service Area and the American Electric Power System



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ENCLOSURE 2 TO AEP:NRC:0909I

INDIANA MICHIGAN POWER COMPANY'S

PROJECTED CASH FLOW

1993 Internal Cash Flow Projection
for Donald C. Cook Nuclear Plant
($ Millions)

	Actual 1992	Projected 1993
Net Income After Taxes	123.9	109.4
Less Dividends Paid	121.9	119.1
Retained Earnings	2.0	(9.7)
Adjustments:		
Depreciation And Amortization	157.8	154.6
Deferred Operating Costs	(47.2)	32.8
Deferred Federal Income Taxes and Investment Tax Credits	20.2	(48.5)
AFUDC	(3.8)	(2.4)
Total Adjustments	127.0	136.5
Internal Cash Flow	129.0	126.8
Average Quarterly Cash Flow	32.3	31.7
Average Cash Balances and Short-Term Investments	7.6	10.2
Total	39.9	41.9

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

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