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POWERS,R.P. Indiana Michigan Power Co.
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SUBJECT: "Indiana Michigan Power Co 1998 Annual Rept." Projected cash flow for 1999,included.With 990528 ltr.

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Power Company
500 Circle Drive
Buchanan, MI 49107 1373

INDIANA
MICHIGAN
POWER

May 28, 1999

AEP:NRC:09090

Docket Nos.: 50-315
50-316

U. S. Nuclear Regulatory Commission
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Donald C. Cook Nuclear Plant Units 1 and 2
FINANCIAL INFORMATION FOR
INDIANA MICHIGAN POWER COMPANY

Gentlemen:

In accordance with 10 CFR 50.71(b), Indiana Michigan Power Company is submitting its 1998 annual report (attachment 1). Also in accordance with 10 CFR 140.21(e) a copy of Indiana Michigan Power Company's projected cash flow for 1999 (attachment 2) is being provided.

The NRC staff has been notified that this transmittal was delayed due to an administrative error in the Regulatory Affairs Department. This condition has been entered into our corrective action program to ensure timely resolution.

Sincerely,

R. P. Powers

R. P. Powers
Vice President

/mjg

Attachments

c: J. E. Dyer
MDEQ - DW & RPD
NRC Resident Inspector
R. Whale

1/1

M004

ATTACHMENT 1 TO AEP:NRC:09090

INDIANA MICHIGAN POWER COMPANY'S
ANNUAL REPORT FOR 1998

Indiana Michigan Power Company

1998 Annual Report

AMERICAN ELECTRIC POWER

AEP: America's Energy Partner℠

INDIANA MICHIGAN POWER COMPANY
AND SUBSIDIARIES
One Summit Square, P.O. Box 60, Fort Wayne, Indiana 46801

CONTENTS

BACKGROUND

INDIANA MICHIGAN POWER COMPANY (the Company) is engaged in the generation, sale, purchase, transmission and distribution of electric power. The Company serves approximately 554,000 retail customers in northern and eastern Indiana and a portion of southwestern Michigan and sells and transmits power at wholesale to other electric utilities, municipalities, electric cooperatives and non-utility entities engaged in the wholesale power market. Approximately 83% of the Company's retail sales are in Indiana and 17% in Michigan. The principal industries served are primary metals, electrical and electronic machinery, transportation equipment, chemicals and allied products, fabricated metal products and rubber and miscellaneous plastic products.

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

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

DIRECTORS

Karl G. Boyd	Henry W. Fayne (c)	David B. Synowiec
Coulter R. Boyle, III	James A. Kobyra (d)	Joseph H. Vipperman
Gregory A. Clark	William J. Lhota	William E. Walters
Peter J. DeMaria (a)	Gerald P. Maloney (a)	Earl H. Wittkamper
William N. D'Onofrio (b)	James J. Markowsky	
E. Linn Draper, Jr.	Armando A. Pena (c)	

OFFICERS

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

William J. Lhota
President and Chief Operating Officer

A. Alan Blind (e)
Vice President, Nuclear Engineering

Coulter R. Boyle, III
Vice President

Peter J. DeMaria (a)
Vice President and Controller

Henry W. Fayne (c)
Vice President

Eugene E. Fitzpatrick (f)
Vice President

Gerald P. Maloney (a)
Vice President

James J. Markowsky
Vice President

Armando A. Pena (c)
Vice President, Treasurer and Chief Financial Officer

Robert P. Powers (g)
Vice President

Michael W. Rencheck (h)
Vice President - Nuclear Engineering

John R. Sampson (i)
Site Vice President, Donald C. Cook Plant

Joseph H. Vipperman
Vice President

Leonard V. Assante (c)
Controller and Chief Accounting Officer

John F. DiLorenzo, Jr.
Secretary

Elio Bafile
Assistant Controller and Assistant Secretary

Timothy P. Bowman
Assistant Controller

William L. Scott
Assistant Controller

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

Thomas G. Berkemeyer (d)
Assistant Secretary

Maurice C. McIntyre
Assistant Secretary

John B. Shinnock
Assistant Secretary

Bruce M. Barber
Assistant Treasurer

Christopher J. Keklak
Assistant Treasurer

As of January 1, 1999 the current directors and officers of Indiana Michigan Power Company were employees of American Electric Power Service Corporation with six exceptions: Messrs. Boyd, Boyle, Clark, McIntyre, Walters and Wittkamper, who were employees of Indiana Michigan Power Company.

(a) Resigned June 1, 1998
(b) Resigned January 28, 1998
(c) Elected June 1, 1998
(d) Elected January 28, 1998
(e) Resigned June 17, 1998
(f) Resigned May 1, 1998
(g) Elected August 27, 1998
(h) Elected December 16, 1998
(i) Elected January 15, 1998

Selected Consolidated Financial Data

	Year Ended December 31,				
	1998	1997	1996	1995	1994
			(in thousands)		
INCOME STATEMENTS DATA:					
Operating Revenues	$1,405,794	$1,339,232	$1,328,493	$1,283,157	$1,251,309
Operating Expenses	1,239,787	1,131,444	1,108,076	1,077,434	1,029,340
Operating Income	166,007	207,788	220,417	205,723	221,969
Nonoperating Income (Loss)	(839)	4,415	2,729	6,272	7,428
Income Before Interest Charges	165,168	212,203	223,146	211,995	229,397
Interest Charges	68,540	65,463	65,993	70,903	71,895
Net Income	96,628	146,740	157,153	141,092	157,502
Preferred Stock Dividend Requirements	4,824	5,736	10,681	11,791	11,681
Earnings Applicable to Common Stock	$ 91,804	$ 141,004	$ 146,472	$ 129,301	$ 145,821

	Year Ended December 31,				
	1998	1997	1996	1995	1994
			(in thousands)		
BALANCE SHEETS DATA:					
Electric Utility Plant	$4,631,848	$4,514,497	$4,377,669	$4,319,564	$4,269,306
Accumulated Depreciation and Amortization	2,081,355	1,973,937	1,861,893	1,751,965	1,659,940
Net Electric Utility Plant	$2,550,493	$2,540,560	$2,515,776	$2,567,599	$2,609,366
Total Assets	$4,148,523	$3,967,798	$3,897,484	$3,928,337	$3,878,035
Common Stock and Paid-in Capital	$ 789,189	$ 789,056	$ 787,856	$ 787,686	$ 790,234
Retained Earnings	253,154	278,814	269,071	235,107	216,658
Total Common Shareholder's Equity	$1,042,343	$1,067,870	$1,056,927	$1,022,793	$1,006,892
Cumulative Preferred Stock:					
Not Subject to Mandatory Redemption	$ 9,273	$ 9,435	$ 21,977	$ 52,000	$ 52,000
Subject to Mandatory Redemption (a)	68,445	68,445	135,000	135,000	135,000
Total Cumulative Preferred Stock	$ 77,718	$ 77,880	$ 156,977	$ 187,000	$ 187,000
Long-term Debt (a)	$1,175,789	$1,049,237	$1,042,104	$1,040,101	$1,069,887
Obligations Under Capital Leases (a)	$ 186,427	$ 195,227	$ 130,965	$ 142,506	$ 152,589
Total Capitalization and Liabilities	$4,148,523	$3,967,798	$3,897,484	$3,928,337	$3,878,035

(a) Including portion due within one year.

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

This discussion includes forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. These forward-looking statements reflect assumptions, and involve a number of risks and uncertainties. Among the factors that could cause actual results to differ materially from forward looking statements are: electric load and customer growth; abnormal weather conditions; available sources and costs of fuels; availability of generating capacity; the speed and degree to which competition is introduced to the power generation business, the structure and timing of a competitive market and its impact on energy prices or fixed rates; the ability to recover stranded costs in connection with possible deregulation of generation; new legislation and government regulations; the ability of the Company to successfully control its costs; the economic climate and growth in our service territory; unforeseen events affecting the Company's nuclear plant which is on an extended safety related shutdown; unforeseen problems or failures related to Year 2000 readiness of computer software and hardware; inflationary trends; electricity market prices; interest rates; and other risks and unforeseen events. This discussion contains a "Year 2000 Readiness Disclosure" within the meaning of the Year 2000 Information and Readiness Disclosure Act.

Indiana Michigan Power Company (the Company) is a wholly-owned subsidiary of American Electric Power Company, Inc. (AEP Co., Inc.), a public utility holding company. The Company is engaged in the generation, purchase, sale, transmission and distribution of electric power to 554,000 retail customers in its service territory in northern and eastern Indiana and a portion of southwestern Michigan and conducts business as American Electric Power (AEP). The Company supplies electric power to the AEP System Power Pool (AEP Power Pool) and shares the revenues and costs of AEP Power Pool wholesale sales to utility systems and power marketers. The Company also sells wholesale power to municipalities and electric cooperatives. As a member of the AEP Power Pool and a signatory company to the AEP System Transmission Equalization Agreement, the Company's generation and transmission facilities are operated in conjunction with the facilities of certain other affiliated utilities as an integrated utility system.

Results of Operations

Although operating revenues increased $67 million or 5% in 1998 and $11 million or 1% in 1997, net income decreased in both years. Net income declined $50 million or 34% in 1998 due to increased purchased power and maintenance expense related to an extended outage of the Company's two unit Donald C. Cook Nuclear Plant (Cook Plant) which was shutdown in September 1997 and losses on certain non-regulated energy trades outside of the AEP Power Pool's traditional marketing area. The 1997 decline of $10 million or 7% resulted from increases in purchased power and other operation expenses due in part to the nuclear plant outage.

Operating Revenues Increase

Operating revenues increased 5% in 1998 following a 1% increase in 1997. The increases in operating revenues in 1998 and 1997 can be attributed mainly to increased retail revenues. The following analyzes the

changes in operating revenues:

(Dollars in Millions)	1998 Amount	1998 %	1997 Amount	1997 %
	Increase (Decrease) From Previous Year			
Retail:				
Residential	$ 26.4		$ 4.3	
Commercial	26.1		10.3	
Industrial	38.1		19.4	
Other	0.4		-	
	91.0	9.6	34.0	3.7
Wholesale	(40.6)	(11.2)	(29.1)	(7.4)
Transmission	13.4	83.2	4.3	35.9
Miscellaneous	2.8	27.6	1.5	18.6
Total	$ 66.6	5.0	$ 10.7	0.8

Revenues from retail customers increased in 1998 due to the accrual of revenues under fuel adjustment clauses for the increased cost of replacement power and increased fossil fuel usage necessitated by the extended outage of the Company's two nuclear units and a 3% increase in sales. The increase in retail revenues in 1997 resulted from the accruals of revenues to be recovered under power supply recovery mechanisms. Under the retail jurisdictional fuel clauses, revenues are accrued for the unrecovered cost of fuel in both retail jurisdictions and for replacement power costs in the Michigan jurisdiction until approved for billing.

The Company as part of the AEP System shares costs and benefits of the System's generating facilities through the AEP Power Pool. The cost of the System's generating capacity is allocated among the AEP Power Pool members, based on their relative peak demands and generating reserves through the payment or receipt of capacity charges and credits. AEP Power Pool members are also compensated for the out-of-pocket costs of energy delivered to the AEP Power Pool and charged for energy received from the AEP Power Pool.

The AEP Power Pool calculates each Company's prior twelve month peak demand relative to the total peak demand of all member companies as a basis for sharing revenues and costs. The result of this calculation is each Company's member load ratio (MLR) which determines each Company's percentage share of revenues or costs. During 1998 the Company's MLR increased resulting in the Company being allocated a larger share of wholesale revenues and expenses from the AEP Power Pool.

In 1997 management decided to develop a power marketing and trading business. The power marketing and trading business is conducted by the AEP Power Pool and its revenues and expenses are allocated to AEP Power Pool members based on MLR.

Wholesale revenues declined in 1998 due to a decline in sales to the AEP Power Pool reflecting the unavailability of the nuclear units. The decline was partially offset by the Company's share of increased power marketing sales and trading activities. A decrease in sales to the AEP Power Pool due mainly to the outage of Cook Plant is also the primary reason for the decline in wholesale revenues in 1997.

Operating Expenses Increase

Total operating expenses increased 10% in 1998 and 2% in 1997 primarily due to an increase in power purchases. The changes in operating expenses were:

(dollars in millions)	1998 Amount	1998 %	1997 Amount	1997 %
	Increase (Decrease) From Previous Year			
Fuel	$(53.8)	(23.8)	$(9.8)	(4.2)
Purchased Power	133.3	80.9	26.1	18.8
Other Operation	13.1	3.9	23.6	7.6
Maintenance	39.8	33.8	2.5	2.2
Depreciation and Amortization	4.3	3.1	0.4	0.3
Amortization of Rockport Plant Unit 1 Phase-in Plan Deferrals	(11.9)	(100.0)	(3.8)	(24.1)
Taxes Other Than Federal Income Taxes	2.6	4.1	(8.8)	(11.9)
Federal Income Taxes	(19.1)	(27.0)	(6.8)	(8.8)
Total	$108.3	9.6	$23.4	2.1

The decrease in fuel expense in 1998 and 1997 reflects the decrease in nuclear generation as both nuclear units were unavailable from September 1997 through the end of 1998. See Cook Nuclear Plant Shutdown discussed below.

Purchased power expense increased significantly in 1998 and 1997 due to increased purchases from the AEP Power Pool and the Company's MLR share of increased purchases of electricity by the AEP Power Pool. The purchases replace power usually generated by the unavailable nuclear units and supply the electricity for the AEP Power Pool's marketing sales.

The increases in other operation and maintenance expenses in 1998 were due to expenditures to prepare the nuclear units for restart. Other operation expense increased in 1997 due to the effect of gains on the disposition of emission allowances recorded in 1996 and higher administrative and general costs and uncollectible accounts receivable expenses.

The recovery period for Rockport Plant Unit 1 costs deferred under rate phase-in plans in the Indiana and the Federal Energy Regulatory Commission (FERC) jurisdictions ended in 1997 causing the decrease in the amortization of phase-in plan deferrals. The deferred costs were amortized over a 10-year period commensurate with their collection from customers.

The decrease in taxes other than federal income taxes in 1997 was due to decreases in real and personal property taxes, Michigan single business tax and Indiana supplemental income tax.

Federal income taxes attributable to operations decreased in 1998 and 1997 due to decreases in pre-tax operating income.

Nonoperating Income

The decline in nonoperating income is due to losses in 1998 from non-regulated electricity trading activities. These trading activities are for forward electricity sales and purchases outside of the AEP Power Pool's traditional marketing area and also include electricity derivatives such as options, swaps, etc. Open trades are marked-to-market and recorded in nonoperating income.

Business Outlook

The most significant factors affecting the Company's future earnings are the restart of the Cook Plant units (discussed below under Cook Nuclear Plant Shutdown) and the ability to recover costs as the electric generating business becomes more competitive. The introduction of competition and customer choice for retail customers in the Company's service territory has been slow and continues at a deliberate pace as legislators and regulatory officials recognize the complexity of the issues. Federal legislation has been proposed to mandate competition and customer choice at the retail level, and several states have introduced or are considering similar legislation. Certain states, including California, instituted full customer choice in 1998. The Michigan Commission has started a program for certain utilities to phase-in to competition with the objective of providing full customer choice by 2002. The Company has begun discussions with the Michigan Commission and other interested parties to formulate a plan. The actions by the Michigan Commission were not mandated by legislation and are subject to a number of uncertainties and it is not presently possible to determine what impact if any the resolution of these matters will have on the operations of the Company. The Company's Michigan jurisdiction accounts for 13% of total revenues. Indiana is

considering legislative initiatives to move to customer choice, although the timing is uncertain. The Company supports customer choice and is proactively involved in discussions at both the state and federal levels regarding the best competitive market structure and method to transition to a competitive marketplace.

As the pricing of generation in the electric energy market evolves from regulated cost-of-service ratemaking to market-based rates, many complex issues must be resolved, including the recovery of stranded costs. Stranded costs are those costs above market that potentially would not be recoverable in a competitive market. At the wholesale level recovery of stranded costs under certain conditions was addressed by the FERC when it established rules for open transmission access and competition in the wholesale markets. However, the issue of stranded cost is unresolved at the retail level where it is much larger than it is at the wholesale level. The amount of stranded cost the Company could experience depends on the timing and extent to which competition is introduced to its generation business and the future market prices of electricity. The recovery of stranded cost is dependent on the terms of future legislation and related regulatory proceedings.

Under the provisions of Statement of Financial Accounting Standards (SFAS) 71 "Accounting for the Effects of Certain Types of Regulation," regulatory assets (deferred expenses) and regulatory liabilities (deferred revenues) are included in the consolidated balance sheets of regulated utilities in accordance with regulatory actions to match expenses and revenues with cost-based rates in the same accounting period. In order to maintain net regulatory assets on the balance sheet, SFAS 71 requires that rates charged to customers be cost-based and provide for the recovery of deferred expenses over future accounting periods. In the event a portion of the Company's business no longer meets the requirements of SFAS 71, SFAS 101 "Accounting for the Discontinuance of Application of Statement 71" requires that net regulatory assets be written off for that portion of the business. The provisions of SFAS 71 and SFAS 101 never anticipated that deregulation would include an extended transition period or that it could provide for recovery of stranded costs during and after the transition period. In 1997 the Financial Accounting Standards Board's (FASB) Emerging Issues Task Force (EITF) addressed such a situation with the consensus reached on issue 97-4 that requires the application of SFAS 71 to a segment of a regulated electric utility cease when that segment is subject to a legislatively approved plan for competition or an enabling rate order is issued containing sufficient detail for the utility to reasonably determine what the plan would entail. The EITF indicated that the cessation of application of SFAS 71 would require that regulatory assets and impaired plant be written off unless they are recoverable in future rates.

Although certain FERC orders provide for competition in the firm wholesale market, that market is a relatively small part of our business and most of our firm wholesale sales are still under cost-of-service contracts. As a result, the Company's generation business is still cost-based regulated and should remain so for the near future. We believe that enabling state legislation should provide for the recovery of any generation-related net regulatory assets and other reasonable stranded costs from impaired generating assets. However, if in the future the Company's generation business were to no longer be cost-based regulated and if it

were not possible to demonstrate probability of recovery of resultant stranded costs including regulatory assets, results of operations, cash flows and financial condition would be adversely affected.

Litigation
Corporate Owned Life Insurance

The Internal Revenue Service (IRS) agents auditing the AEP System's consolidated federal income tax returns for the years 1991 to 1993 requested a ruling from their National Office that certain interest deductions claimed by the Company relating to AEP's corporate owned life insurance (COLI) program should not be allowed. As a result of a suit filed by the Company in United States (US) District Court (discussed below) this request for ruling was withdrawn by the IRS agents. Adjustments have been or will be proposed by the IRS disallowing COLI interest deductions for taxable years 1991-96. A disallowance of the COLI interest deductions through December 31, 1998 would reduce earnings by approximately $66 million (including interest). The Company has made no provision for any possible adverse earnings impact from this matter.

In 1998 the Company made payments of taxes and interest attributable to COLI interest deductions for taxable years 1991-97 to avoid the potential assessment by the IRS of any additional above market rate interest on the contested amount. The payments to the IRS are included on the balance sheet in other property and investments pending the resolution of this matter. The Company will seek refund, either administratively or through litigation, of all amounts paid plus interest. In order to resolve this issue without further delay, on March 24, 1998, the Company filed suit against the US in the US District Court for the Southern District of Ohio. Management believes that it has a meritorious position and will vigorously pursue this lawsuit. In the event the resolution of this matter is unfavorable, it will have a material adverse impact on results of operations and cash flows.

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

Cost Containment and Process Improvement

Efforts continue to reduce the cost of products and services in order to maintain competitiveness. The accounting department completed its consolidation of operations and the marketing department completed its reorganization in 1998 producing cost reductions. In 1998 the Company reviewed its staffing levels for power generation and energy delivery and developed plans to reduce staff in 1999. The cost of staff reductions planned for 1999 was provided for in the fourth quarter of 1998. Although cost savings are expected to result from the power generation and energy delivery reorganizations, the Company continues to incur expenses related to investments in marketing and customer services and the reengineering and improvement of business processes.

During 1998, the Company completed installation of a new unified customer service system which is designed to support customer requests for service, billings, accounts receivable, credit and collection functions. On January 1, 1999, the Company's new financial data base and PeopleSoft client

server accounting and purchasing software became operational. The move to client server business software and related online data bases will empower employees to maximize the benefits of their personal computers and will position them to better access the power of the Internet and other new technologies.

Costs for Spent Nuclear Fuel and Decommissioning

The Company, as the owner of the Cook Plant, like other nuclear power plant owners, has a significant future financial commitment to safely dispose of spent nuclear fuel (SNF) and decommission and decontaminate the plant. The Nuclear Waste Policy Act of 1982 established federal responsibility for the permanent off-site disposal of SNF and high-level radioactive waste. By law we participate in the Department of Energy's (DOE) SNF disposal program which is described in Note 3 of the Notes to Consolidated Financial Statements. Since 1983 we have collected $272 million from customers for the disposal of nuclear fuel consumed at the Cook Plant. Of these funds, $115 million has been deposited in external trust funds to provide for the future disposal of SNF and $157 million has been remitted to the DOE. Under the provisions of the Nuclear Waste Policy Act, collections from customers are to provide the DOE with money to build a repository for SNF. However, in December 1996, the DOE notified the Company that it would be unable to begin accepting SNF by the January 1998 deadline required by law.

As a result of DOE's failure to make sufficient progress toward a permanent repository or otherwise assume responsibility for SNF, the Company along with a number of unaffiliated utilities and states filed suit in the US Court of Appeals for the District of Columbia Circuit requesting, among other things, that the court order DOE to meet its obligations under the law. The court ordered the parties to proceed with contractual remedies but declined to order DOE to begin accepting SNF for disposal. DOE estimates its planned site for the nuclear waste will not be ready until 2010. In June 1998, the Company filed a complaint in the US Court of Federal Claims seeking damages in excess of $150 million due to the DOE's partial material breach of its unconditional contractual deadline to begin disposing of SNF generated by the Cook Plant. Similar lawsuits have been filed by other utilities. As long as the delay in the availability of a government approved storage repository for SNF continues, the cost of both temporary and permanent storage will increase.

The cost to decommission the Cook Plant is affected by both Nuclear Regulatory Commission (NRC) regulations and the delayed SNF disposal program. Studies completed in 1997 estimate the cost to decommission the Cook Plant ranges from $700 million to $1,152 million in 1997 dollars. This estimate could escalate due to continued uncertainty in the SNF disposal program and the length of time that SNF may need to be stored at the plant site. External trust funds have been established and funded with amounts collected from customers to decommission the plant. At December 31, 1998, the total decommissioning trust fund balance was $443 million which includes earnings on the trust investments. We will work with regulators and customers to recover the remaining estimated cost of decommissioning the Cook Plant. However, future results of operations, cash flows and possibly financial condition would be adversely affected if the cost of SNF disposal and decommissioning continue to increase and cannot be recovered from customers.

Cook Nuclear Plant Shutdown

Management shut down both units of the Cook Plant in September 1997 due to questions, which arose during a NRC architect engineer design inspection, regarding the operability of certain safety systems. The NRC issued a Confirmatory Action Letter in September 1997 requiring the Company to address the issues identified in the letter. We are working with the NRC to resolve the remaining open issue in the letter.

In April 1998 the NRC notified the Company that it had convened a Restart Panel for Cook Plant. A list of required restart activities was provided by the NRC in July 1998 and in October the NRC expanded the list. In order to identify and resolve the issues necessary to restart the Cook units, the Company is and will be meeting with the Panel on a regular basis, until the units are returned to service.

In January 1999 we announced that we will conduct additional engineering reviews at the Cook Plant that will delay restart of the units. Previously, the units were scheduled to return to service at the end of the first and second quarters of 1999. The decision to delay restart resulted from internal assessments that indicated a need to conduct expanded system readiness reviews. A new restart schedule will be developed based on the results of the expanded reviews and should be available in June 1999. When maintenance and other activities required for restart are complete, the Company will seek concurrence from the NRC to return the Cook Plant to service. Until these additional reviews are completed, management is unable to determine when the units will be returned to service.

One of the steps the Company has taken toward expediting the restart of the Cook units is to augment its existing nuclear generation management and staff with personnel experienced in restarting unaffiliated companies' nuclear plants during NRC supervised extended outages.

The costs incurred in 1997 and 1998 for restart of the Cook units were $6 million and $78 million, respectively, and were recorded as operation and maintenance expense. Reductions in other operation and maintenance expenses partially offset these costs. Currently incremental restart expenses are approximately $12 million a month.

In July 1998 the Company received an "adverse trend letter" from the NRC indicating that NRC senior managers determined that there had been a slow decline in performance at the Cook Plant during the 18 month period preceding the letter. The letter indicated that the NRC will closely monitor efforts to address issues at Cook Plant through additional inspection activities. In October 1998 the NRC issued the Company a Notice of Violation and proposed a $500,000 civil penalty for alleged violations at the Cook Plant discovered during five inspections conducted between August 1997 and April 1998. The penalty was paid.

The cost of electricity supplied to retail customers rose due to the outage of the two units since higher cost coal-fired generation and coal based purchased power were substituted for low cost nuclear generation. The Indiana and Michigan retail jurisdictional fuel cost recovery mechanisms permit the recovery, subject to regulatory commission review and approval, of changes in fuel costs including the fuel component of purchased power in the Indiana jurisdiction and changes in replacement power in the Michigan jurisdiction. Under these fuel cost recovery mechanisms, retail rates

contain a fuel cost adjustment factor that reflects estimated fuel costs for the period during which the factor will be in effect subject to reconciliation to actual fuel costs in a future proceeding. When actual fuel costs exceed the estimated costs reflected in the billing factor a regulatory asset is recorded and revenues are accrued. Therefore, a regulatory asset has been recorded and revenues accrued in anticipation of the future reconciliation and billing under the fuel cost recovery mechanisms of the higher fuel costs to replace Cook energy during the extended outage. At December 31, 1998, the regulatory asset was $65 million.

The Indiana Utility Regulatory Commission (IURC) approved, subject to future reconciliation or refund, agreements authorizing the Company, during the billing months of July 1998 through March 1999, to include in rates a fuel cost adjustment factor less than that requested. The agreements provide the parties to the proceedings with the opportunity to conduct discovery regarding certain issues that were raised in the proceedings, including the appropriateness of the recovery of replacement energy cost due to the extended Cook Plant outage, in anticipation of resolving the issues in a future fuel cost adjustment proceeding.

On March 16, 1999 a settlement agreement was filed with the IURC resolving all matters related to the reasonableness of fuel costs and all outage issues during an extended outage of the Cook Plant. The settlement agreement, which is subject to IURC approval, provides for, among other things, a credit of $55 million to Indiana retail customers; authorization to defer any unrecovered fuel revenues accrued between September 9, 1997 and December 31, 1999 including the $55 million; authorization to defer up to $150 million of incremental operation and maintenance restart costs for the Cook Plant above the base rate level incurred during 1999; amortization of the fuel recoveries and restart cost deferrals over a five-year period ending December 31, 2003; a freeze in base rates though December 31, 2003; and a cap on fuel recovery charges through March 1, 2004. The $55 million credit will be refunded through customer's bills during the months of July, August and September 1999. If the IURC does not approve the settlement, the issue of recovery of replacement energy costs would be resolved through regulatory hearings.

Unless the costs of the extended outage and restart efforts are recovered from customers, there would be a material adverse effect on results of operations, cash flows, and possibly financial condition.

Environmental Concerns and Issues

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

By-products from the generation of electricity include materials such as ash, slag, sludge, low-level radioactive waste and SNF. Coal combustion by-products are typically disposed of or treated in captive disposal facilities or are beneficially utilized. In addition, our generating plants and transmission and distribution facilities have used asbestos, polychlorinated biphenyls (PCBs) and other hazardous and nonhazardous materials. The

Company is currently incurring costs to safely dispose of such substances. Additional costs could be incurred to comply with new laws and regulations if enacted.

The Comprehensive Environmental Response, Compensation and Liability Act (Superfund) addresses clean-up of hazardous substances at disposal sites and authorized the US Environmental Protection Agency (Federal EPA) to administer the clean-up programs. As of year-end 1998, the Company is currently involved in litigation with respect to one site overseen by the Federal EPA, and has been named by the Federal EPA as a potentially responsible party (PRP) for two other sites. There is one additional site for which the Company has received an information request which could lead to PRP designation. Historically, the Company's liability has been resolved for a number of sites with no significant effect on results of operations and present estimates do not anticipate material cleanup costs for identified sites for which we have been declared a PRP. However, if for reasons not currently identified significant cleanup costs are incurred, results of operations, cash flows and possibly financial condition would be adversely affected unless the costs can be recovered from customers.

On September 24, 1998, the administrator of Federal EPA signed final rules which require reductions in nitrogen oxides (NOx) emissions in 22 eastern states, including the states in which the generating plants of the Company and its affiliates in the AEP System are located. The implementation of the final rules would be achieved through the revision of state implementation plans (SIPs) by September 1999. SIPs are a procedural method used by each state to comply with Federal EPA rules. The final rules anticipate the imposition of a NOx reduction on utility sources of approximately 85% below 1990 emission levels by the year 2003. On October 30, 1998, a number of utilities, including the Company and the other operating companies of the AEP System, filed a petition in the US Court of Appeals for the District of Columbia Circuit seeking a review of the final rules.

Should the states fail to adopt the required revisions to their SIPs within one year of the date the final rules were signed (September 24, 1999), Federal EPA has proposed to implement a federal plan to accomplish the NOx reductions. Federal EPA also proposed the approval of portions of petitions filed by eight northeastern states that would result in imposition of NOx emission reductions on utility and industrial sources in upwind midwestern states. These reductions are substantially the same as those required by the final NOx rules and could be adopted by Federal EPA in the event the states fail to implement SIPs in accordance with the final rules.

Preliminary estimates indicate that compliance could result in required capital expenditures of approximately $169 million. Compliance costs cannot be estimated with certainty and the actual costs incurred to comply could be significantly different from this preliminary estimate depending upon the compliance alternatives selected to achieve reductions in NOx emissions. Unless such costs are recovered from customers, they would have a material adverse effect on results of operations, cash flows and possibly financial condition.

At the Third Conference of the Parties to the United Nations Framework Convention on Climate Change held in Kyoto, Japan in December 1997 more than 160 countries, including the US, negotiated a treaty requiring

legally-binding reductions in emissions of greenhouse gases, chiefly carbon dioxide, which many scientists believe are contributing to global climate change. The treaty, which requires the advice and consent of the US Senate for ratification, would require the US to reduce greenhouse gas emissions seven percent below 1990 levels in the years 2008-2012. Although the US has agreed to the treaty and signed it on November 12, 1998, President Clinton has indicated that he will not submit the treaty to the Senate for consideration until it contains requirements for "meaningful participation by key developing countries" and the rules, procedures, methodology and guidelines of the treaty's market-based policy instruments, joint implementation programs and compliance enforcement provisions have been negotiated. At the Fourth Conference of the Parties, held in Buenos Aires, Argentina, in November 1998, the parties agreed to a work plan to complete negotiations on outstanding issues with a view toward approving them at the Sixth Conference of the Parties to be held in December 2000. We will continue to work with the Administration and Congress to monitor the development of public policy on this issue.

If the Kyoto treaty is approved by Congress, the costs to comply with the emission reductions required by the treaty are expected to be substantial and would have a material adverse impact on results of operations, cash flows and possibly financial condition if not recovered from customers.

Financial Condition

The Company issued $175 million principal amount of long-term obligations in 1998 at interest rates ranging from 6.45% to 7.6%. The principal amount of long-term debt retirements, including maturities, totaled $55 million at interest rates ranging from 7% to 7.8%. Our senior secured debt/first mortgage bond ratings are: Moody's, Baa1; Standard & Poor's, A-; and Fitch, BBB+.

Gross plant and property additions were $159 million in 1998 and $235 million in 1997. Management estimates construction expenditures for the next three years to be $366 million which includes the replacement of the Cook Plant Unit 1 steam generators. The funds for construction of new facilities and improvement of existing facilities can come from a combination of internally generated funds, short-term and long-term borrowings, preferred stock issuances and investments in common equity by the Company's parent, American Electric Power Company, Inc. (AEP Co., Inc.) However, all of the construction expenditures for the next three years are expected to be financed with internally generated funds.

When necessary the Company generally issues short-term debt to provide for interim financing of capital expenditures that exceed internally generated funds. At December 31, 1998, $763 million of unused short-term lines of credit shared with other AEP System companies were available. Short-term debt borrowings are limited by provisions of the Public Utility Holding Company Act of 1935 to $300 million. Generally periodic reductions of outstanding short-term debt are made through issuances of long-term debt and additional capital contributions by the parent company.

The Company's earnings coverage presently exceeds all minimum coverage requirements for the issuance of mortgage bonds and preferred stock. The minimum coverage ratios are 2.0 for mortgage bonds and 1.5 for preferred stock. At December 31, 1998, the mortgage bond and preferred stock coverage ratios were 6.39 and 2.08, respectively.

The Company is committed under unit power agreements to purchase all of an affiliate's share, 50% of the 2,600 megawatt (mw) Rockport Plant capacity, unless it is sold to other utilities. The affiliate has a long-term unit power agreement for the sale of 455 mw to an unaffiliated utility. Revenues received under this agreement (which expires at the end of 1999) were $70 million in 1998. An agreement between the affiliate which owns Rockport Plant and another affiliate provides for the sale of 390 mw of capacity to that affiliate through 2004.

Market Risks

The Company has certain market risks inherent in its business activities from changes in electricity commodity prices and interest rates. The trading of electricity and related financial derivative instruments through the AEP Power Pool on the Company's behalf exposes the Company to market risk. Market risk represents the risk of loss that may impact the Company due to adverse changes in electricity commodity market prices and rates. In 1998 the AEP Power Pool substantially increased the volume of its wholesale power marketing and trading activities. Various policies and procedures have been established to manage market risk exposures including the use of a risk measurement model utilizing Value at Risk (VaR). Throughout the year ending December 31, 1998, the Company's share of the highest, lowest and average quarterly VaR in the wholesale trading portfolio was less than $2 million at a 95% confidence level with a holding period of three business days. The AEP Power Pool uses the variance-covariance method for calculating VaR based on three months of daily prices. Based on this VaR analysis, at December 31, 1998 a near term change in commodity prices is not expected to have a material effect on the Company's results of operations, cash flows or financial condition.

The Company is exposed to changes in interest rates primarily due to short-term and long-term borrowings to fund its business operations. The debt portfolio has both fixed and variable interest rates with terms from one day to forty years and an average duration of six years at December 31, 1998. The Company measures interest rate market risk exposure utilizing a VaR model. The model is based on the Monte Carlo method of simulated price movements with a 95% confidence level and a one year holding period. The volatilities and correlations are based on three years of monthly prices. The risk of potential loss in fair value attributable to the Company's exposure to interest rates, primarily related to long-term debt with fixed interest rates, was $102 million at December 31, 1998. The Company would not expect to liquidate its entire debt portfolio in a one year holding period. Therefore, a near term change in interest rates should not materially affect results of operations or the consolidated financial position of the Company. Also since the Company's rates are cost-based regulated, the risk of interest rate changes on debt used to finance regulated operations is mitigated.

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

Other Matters

Computer Issue - Year 2000

On or about midnight on December 31, 1999, digital computing systems may begin to produce erroneous results or fail, unless these systems are modified or replaced, because such systems may be programmed incorrectly and interpret the date of January 1, 2000 as being January 1st of the year 1900 or another incorrect date. In addition, certain systems may fail to detect that the year 2000 is a leap year. Problems can also arise earlier than January 1, 2000, as dates in the next millennium are entered into non-Year 2000 ready programs.

Readiness Program - Internally, the Company, through the AEP System, is modifying or replacing its computer hardware and software programs to minimize Year 2000-related failures and repair such failures if they occur. This includes both information technology systems (IT), which are mainframe and client server applications, and embedded logic systems (non-IT), such as process controls for energy production and delivery. Externally, the problem is being addressed with entities that interact with the Company, including suppliers, customers, creditors, financial service organizations and other parties essential to the Company's operations. In the course of the external evaluation, the Company has sought written assurances from third parties regarding their state of Year 2000 readiness.

Another issue we are addressing is the impact of electric power grid problems that may occur outside of our transmission system. The Company, along with other electric utilities in North America, regularly submits information to the North American Electric Reliability Council (NERC) as part of NERC's Year 2000 readiness program. NERC then publicly reports summary information to the DOE regarding the Year 2000 readiness of electric utilities. In 1999 AEP plans to participate in two NERC-sponsored coordinated electric industry Year 2000 readiness drills.

The second NERC report, dated January 11, 1999 and entitled: Preparing the Electric Power Systems of North American for Transition to the Year 2000 - A Status Report and Work Plan, Fourth Quarter 1998, states that: "With more than 44% of mission critical components tested through November 30, 1998, findings continue to indicate that transition through critical Year 2000 (Y2K) rollover dates is expected to have minimal impact on electric system operations in North America." The Company continues to set a target date of June 30, 1999 for having all mission critical and high priority systems and components Y2K ready.

Through the Electric Power Research Institute, an electric industry-wide effort has been established to deal with Year 2000 problems affecting embedded systems. Under this effort, participating utilities are working together to assess specific vendors' system problems and test plans.

The state regulatory commissions in the Company's service territory are also reviewing the Year 2000 readiness of the Company.

Company's State of Readiness - Work has been prioritized in accordance with business risk. The highest priority has been assigned to activities that potentially affect safety, the physical generation and delivery of energy, and communications; followed by back office activities such as customer service/billing, regulatory reporting, internal reporting and administrative activities (e.g. payroll, procurement, accounts

payable); and finally, those activities that would cause inconvenience or productivity loss in normal business operations.

The following chart shows our progress toward becoming ready for the Year 2000 as of December 31, 1998:

	IT SYSTEMS		NON-IT SYSTEMS	
YEAR 2000 PROJECT PHASES	COMPLETION DATE/ESTIMATED COMPLETION DATE	PERCENT COMPLETE	COMPLETION DATE/ESTIMATED COMPLETION DATE	PERCENT COMPLETE
Launch: Initiation of the Year 2000 activities within the organization. Establishment of organizational structure, personnel assignments and budget for the workgroup. Continuous management update and awareness program.	2/24/1998	100%	5/31/1998	100%
Inventory and Assessment: Identifying all Company computer systems that could be affected by the millennium change. Prioritize repair efforts based upon criticality to maintaining ongoing operations.	7/31/1998	100%	2/15/1999	99%
Remediation/Testing: The process of modifying, replacing or retiring those mission critical and high priority digital-based system with problems processing dates past the Year 2000. Testing these systems to ensure that after modifications have been implemented correct date processing occurs and full functionality has been maintained.	6/30/1999	Mainframe: 70% Client Server: 18%	6/30/1999	37%

Costs to Address the Company's Year 2000 Issues - Through December 31, 1998, the Company has spent $4 million on the Year 2000 project and, estimates spending an additional $6 million to $9 million to achieve Year 2000 readiness. Most Year 2000 costs are for software modifications, IT consultants and salaries and are expensed; however, in certain cases the Company has acquired hardware that was capitalized. The Company intends to fund these expenditures through internal sources. Although significant, the cost of becoming Year 2000 compliant is not expected to have a material impact on the Company's results of operations, cash flows or financial condition.

Risks of the Company's Year 2000 Issues - The applications posing the greatest business risk to the Company's operations should they experience Y2K problems are:

- Automated power generation, transmission and distribution systems
- Telecommunications systems
- Energy trading systems
- Time-in-use, demand and remote metering systems for commercial and industrial customers and
- Work management and billing systems.

The potential problems related to erroneous processing by, or failure of, these systems are:

- Power service interruptions to customers
- Interrupted revenue data gathering and collection
- Poor customer relations resulting from delayed billing and settlement.

In addition, although as discussed relationships with third parties, such as suppliers, customers and other electric utilities, are being monitored, these third parties nonetheless represent a risk that cannot be assessed with precision or controlled with certainty.

Due to the complexity of the problem and the interdependent nature of computer systems, if our corrective actions, and/or the actions of others not affiliated with the AEP System, fail for critical applications, Year 2000-related issues may materially adversely affect the Company.

Company's Contingency Plans - To address possible failures of electric generation and delivery of electrical energy due to Year 2000 related failures, we have established a draft Year 2000 contingency plan and submitted it to the East Central Area Reliability Council in December 1998 as part of NERC's review of regional and individual electric utility contingency plans in 1999. NERC's target date is June 1999 for the completion of this contingency plan. In addition, the Company intends to establish contingency plans for its business units to address alternatives if Year 2000 related failures occur. Contingency plans will be developed by the end of 1999. The Company's plans build upon the disaster recovery, system restoration, and contingency planning that we have had in place.

New Accounting Standards

In 1997 the FASB issued SFAS 130 "Reporting Comprehensive Income" and SFAS 131 "Disclosures About Segments of an Enterprise and Related Information." SFAS 130 establishes the standards for reporting and displaying components of "comprehensive income," which is the total of net income and all transactions not included in net income affecting equity except those with shareholders. The Company adopted SFAS 130 in the first quarter of 1998. For 1998 there were no material differences between net income and comprehensive income.

SFAS 131 initiates standards for annual and interim financial statements to report operating segments of a business for which separate financial information is available and regularly evaluated by the chief operating decision maker in allocating resources and reviewing performance. Information about products and services and geographic areas is to be reported at an enterprise-level instead of by segment. SFAS 131 was required to be adopted by the Company for the year ended December 31, 1998 with restatement of prior period comparative information. Adoption of SFAS 131 did not have any effect on results of operations, cash flows or financial condition.

In the first quarter of 1998 the Company adopted the American Institute of Certified Public Accountants' (AICPA) Statement of Position (SOP) 98-1, "Accounting for the Costs of Computer Software Developed or Obtained for Internal Use". The SOP requires the capitalization and amortization of certain costs of acquiring or developing internal use computer software. Previously the Company expensed all software acquisition and development costs. The SOP had to be

adopted at the beginning of a fiscal year with no restatement or retroactive adjustment of prior periods. The adoption of the SOP effective January 1, 1998 did not have a material effect on results of operations, cash flows or financial condition.

In February 1998, the FASB issued SFAS 132 "Employers' Disclosure about Pensions and Other Postretirement Benefits" which revised employers' disclosures about pensions and other postretirement benefit plans and suggested that the disclosure be combined. It did not change the measurement or recognition requirements for postretirement benefit accounting. The adoption of SFAS 132 did not have an effect on results of operations, cash flows or financial condition.

EITF 98-10 "Accounting for Contracts Involved in Energy Trading and Risk Management Activities" was issued in November 1998 to address the application of mark-to-market accounting for energy trading contracts. Under the provisions of this standard, which must be adopted by the Company in January 1999, energy trading contracts can no longer be accounted for on a settlement basis. Instead they are to be marked-to-market. Initial adoption of EITF 98-10 is not expected to have a significant impact on results of operations, cash flows, or financial condition.

The FASB issued SFAS 133 "Accounting for Derivative Instruments and Hedging Activities" in June 1998. SFAS 133 establishes accounting and reporting standards for derivative instruments. It requires that all derivatives be recognized as either an asset or a liability and measured at fair value in the financial statements. If certain conditions are met a derivative may be designated as a hedge of possible changes in fair value of an asset, liability or firm commitment; variable cash flows of forecasted transactions; or foreign currency exposure. The accounting/reporting for changes in a derivative's fair value (gains and losses) depend on the intended use and resulting designation of the derivative. Management is currently studying the provisions of SFAS 133 to determine the impact, of its adoption on January 1, 2000, on results of operations, cash flows and financial condition.

In April 1998 the AICPA issued SOP 98-5 "Reporting on the Costs of Start-up Activities". The SOP clarifies the accounting and reporting for one time start-up activities and organization costs, requiring that they be expensed as incurred. The adoption of this standard in January 1999 is not expected to have a material effect on results of operations, cash flows or financial condition.

INDEPENDENT AUDITORS' REPORT

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

We have audited the accompanying consolidated balance sheets of Indiana Michigan Power Company and its subsidiaries as of December 31, 1998 and 1997, and the related consolidated statements of income, retained earnings, and cash flows for each of the three years in the period ended December 31, 1998. 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, 1998 and 1997, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1998 in conformity with generally accepted accounting principles.

Deloitte & Touche LLP

DELOITTE & TOUCHE LLP
Columbus, Ohio
February 23, 1999
(March 16, 1999 as to Note 4)

Consolidated Statements of Income

	Year Ended December 31,		
	1998	1997	1996
		(in thousands)	
OPERATING REVENUES	$1,405,794	$1,339,232	$1,328,493
OPERATING EXPENSES:			
Fuel	172,592	226,402	236,237
Purchased Power	298,046	164,775	138,687
Other Operation	347,207	334,115	310,513
Maintenance	157,593	117,780	115,300
Depreciation and Amortization	145,112	140,812	140,437
Amortization of Rockport Plant Unit 1 Phase-in Plan Deferrals	-	11,871	15,644
Taxes Other Than Federal Income Taxes	67,592	64,945	73,729
Federal Income Taxes	51,645	70,744	77,529
Total Operating Expenses	1,239,787	1,131,444	1,108,076
OPERATING INCOME	166,007	207,788	220,417
NONOPERATING INCOME (LOSS)	(839)	4,415	2,729
INCOME BEFORE INTEREST CHARGES	165,168	212,203	223,146
INTEREST CHARGES	68,540	65,463	65,993
NET INCOME	96,628	146,740	157,153
PREFERRED STOCK DIVIDEND REQUIREMENTS	4,824	5,736	10,681
EARNINGS APPLICABLE TO COMMON STOCK	$ 91,804	$ 141,004	$ 146,472

See Notes to Consolidated Financial Statements.

Consolidated Balance Sheets

	December 31, 1998	December 31, 1997
	(in thousands)	
ASSETS		
ELECTRIC UTILITY PLANT:		
Production	$2,556,732	$2,545,484
Transmission	913,252	908,736
Distribution	768,803	737,902
General (including nuclear fuel)	236,650	233,888
Construction Work in Progress	156,411	88,487
Total Electric Utility Plant	4,631,848	4,514,497
Accumulated Depreciation and Amortization	2,081,355	1,973,937
NET ELECTRIC UTILITY PLANT	2,550,493	2,540,560
NUCLEAR DECOMMISSIONING AND SPENT NUCLEAR FUEL DISPOSAL TRUST FUNDS	648,307	566,390
OTHER PROPERTY AND INVESTMENTS	197,368	156,228
CURRENT ASSETS:		
Cash and Cash Equivalents	12,465	5,860
Accounts Receivable:		
Customers	94,502	107,087
Affiliated Companies	19,528	15,662
Miscellaneous	18,743	14,561
Allowance for Uncollectible Accounts	(2,027)	(1,188)
Fuel - at average cost	20,857	17,182
Materials and Supplies - at average cost	78,009	78,701
Accrued Utility Revenues	37,277	30,521
Prepayments and Other	18,953	4,685
TOTAL CURRENT ASSETS	298,307	273,071
REGULATORY ASSETS	421,475	400,489
DEFERRED CHARGES	32,573	31,060
TOTAL	$4,148,523	$3,967,798

See Notes to Consolidated Financial Statements.

	December 31, 1998	December 31, 1997
	(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	732,605	732,472
Retained Earnings	253,154	278,814
Total Common Shareholder's Equity	1,042,343	1,067,870
Cumulative Preferred Stock:		
Not Subject to Mandatory Redemption	9,273	9,435
Subject to Mandatory Redemption	68,445	68,445
Long-term Debt	1,140,789	1,014,237
TOTAL CAPITALIZATION	2,260,850	2,159,987
OTHER NONCURRENT LIABILITIES:		
Nuclear Decommissioning	445,934	381,016
Other	240,320	232,667
TOTAL OTHER NONCURRENT LIABILITIES	686,254	613,683
CURRENT LIABILITIES:		
Long-term Debt Due Within One Year	35,000	35,000
Short-term Debt	108,700	119,600
Accounts Payable - General	53,187	36,729
Accounts Payable - Affiliated Companies	37,647	31,665
Taxes Accrued	35,161	46,850
Interest Accrued	15,279	15,741
Obligations Under Capital Leases	9,667	34,033
Other	87,293	63,250
TOTAL CURRENT LIABILITIES	381,934	382,868
DEFERRED INCOME TAXES	559,288	559,708
DEFERRED INVESTMENT TAX CREDITS	129,779	138,045
DEFERRED GAIN ON SALE AND LEASEBACK - ROCKPORT PLANT UNIT 2	88,712	92,419
DEFERRED CREDITS	41,706	21,088
COMMITMENTS AND CONTINGENCIES (Note 3)		
TOTAL	$4,148,523	$3,967,798

See Notes to Consolidated Financial Statements.

Consolidated Statements of Cash Flows

	Year Ended December 31,		
	1998	1997	1996
		(in thousands)	
OPERATING ACTIVITIES:			
Net Income	$ 96,628	$ 146,740	$ 157,153
Adjustments for Noncash Items:			
Depreciation and Amortization	149,209	148,630	148,123
Amortization of Rockport Plant Unit 1 Phase-in Plan Deferrals	-	11,871	15,644
Amortization (Deferral) of Incremental Nuclear Refueling Outage Expenses (net)	14,142	(15,967)	7,662
Deferred Federal Income Taxes	17,905	3,922	(24,687)
Deferred Investment Tax Credits	(8,266)	(8,428)	(8,729)
Over (Under)-recovery of Fuel and Purchased Power	(46,846)	(22,812)	12,477
Changes in Certain Current Assets and Liabilities:			
Accounts Receivable (net)	5,376	(10,456)	(10,235)
Fuel, Materials and Supplies	(2,983)	5,168	903
Accrued Utility Revenues	(6,756)	7,774	5,642
Accounts Payable	22,440	6,502	1,186
Taxes Accrued	(11,689)	(18,550)	(6,296)
Payment of Disputed Tax and Interest Related to COLI	(53,628)	-	-
Other (net)	(8,176)	5,817	(4,502)
Net Cash Flows From Operating Activities	167,356	260,211	294,341
INVESTING ACTIVITIES:			
Construction Expenditures	(147,627)	(122,360)	(95,046)
Proceeds from Sales of Property and Other	4,419	2,016	2,776
Net Cash Flows Used For Investing Activities	(143,208)	(120,344)	(92,270)
FINANCING ACTIVITIES:			
Issuance of Long-term Debt	170,675	47,728	38,579
Retirement of Cumulative Preferred Stock	(120)	(78,877)	(30,568)
Retirement of Long-term Debt	(55,000)	(50,000)	(46,091)
Change in Short-term Debt (net)	(10,900)	76,100	(46,475)
Dividends Paid on Common Stock	(117,464)	(131,260)	(112,508)
Dividends Paid on Cumulative Preferred Stock	(4,734)	(5,931)	(10,498)
Net Cash Flows Used For Financing Activities	(17,543)	(142,240)	(207,561)
Net Increase (Decrease) in Cash and Cash Equivalents	6,605	(2,373)	(5,490)
Cash and Cash Equivalents January 1	5,860	8,233	13,723
Cash and Cash Equivalents December 31	$ 12,465	$ 5,860	$ 8,233

See Notes to Consolidated Financial Statements.

Consolidated Statements of Retained Earnings

	Year Ended December 31,		
	1998	1997	1996
		(in thousands)	
Retained Earnings January 1	$278,814	$269,071	$235,107
Net Income	96,628	146,740	157,153
	375,442	415,811	392,260
Deductions:			
Cash Dividends Declared:			
Common Stock	117,464	131,260	112,508
Cumulative Preferred Stock:			
4-1/8% Series	247	249	495
4.56% Series	67	88	273
4.12% Series	79	80	165
5.90% Series	985	985	2,360
6-1/4% Series	1,266	1,266	1,875
6.30% Series	834	834	2,205
6-7/8% Series	1,255	1,255	2,063
7.08% Series	-	-	531
Total Cash Dividends Declared	122,197	136,017	122,475
Capital Stock Expense	91	980	714
Total Deductions	122,288	136,997	123,189
Retained Earnings December 31	$253,154	$278,814	$269,071

See Notes to Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SIGNIFICANT ACCOUNTING POLICIES:

Organization

Indiana Michigan Power Company (the Company or I&M) is a wholly-owned subsidiary of American Electric Power Company, Inc. (AEP Co., Inc.), a public utility holding company. The Company is engaged in the generation, purchase, sale, transmission and distribution of electric power to 554,000 retail customers in its service territory in northern and eastern Indiana and a portion of southwestern Michigan and conducts business as American Electric Power (AEP). The Company supplies electric power to the AEP System Power Pool (Power Pool) and shares the revenues and costs of Power Pool wholesale sales to utility systems and power marketers. The Company also sells wholesale power to municipalities and electric cooperatives. As a member of the Power Pool and a signatory company to the AEP System Transmission Equalization Agreement, the Company's generation and transmission facilities are operated in conjunction with the facilities of certain other affiliated utilities as an integrated utility system.

The Company has two wholly-owned subsidiaries, that were formerly engaged in coal-mining operations which are consolidated in these financial statements, Blackhawk Coal Company and Price River Coal Company. Blackhawk Coal Company currently leases and subleases portions of its Utah coal rights, land and related mining equipment to unaffiliated companies. Price River Coal Company, which owns no land or mineral rights, is inactive. The Company's River Transportation Division provided barging services to affiliated and unaffiliated companies.

Regulation

As a subsidiary of AEP Co., Inc., 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.

Principles of Consolidation

The consolidated financial statements include the revenues, expenses, cash flows, assets, liabilities and equity of I&M and its wholly-owned subsidiaries. Significant intercompany items are eliminated in consolidation.

Basis of Accounting

As a cost-based rate-regulated entity, I&M's financial statements reflect the actions of regulators that result in the recognition of revenues and expenses in different time periods than enterprises that are not rate regulated. In accordance with Statement of Financial Accounting Standards (SFAS) 71, "Accounting for the Effects of Certain Types of Regulation," regulatory assets (deferred expenses) and regulatory liabilities (deferred income) are recorded to reflect the economic effects of regulation and to match expenses with regulated revenues.

Use of Estimates

The preparation of these financial statements in conformity with generally accepted accounting principles requires in certain

instances the use of estimates. Actual results could differ from those estimates.

Utility Plant

Electric utility plant is stated at original cost and is generally subject to first mortgage liens. Additions, major replacements and betterments are added to the plant accounts. Retirements of plant are deducted from the electric utility plant in service account and are deducted from accumulated depreciation together with associated removal costs, net of salvage. The costs of labor, materials and overheads incurred to operate and maintain utility plant are included in operating expenses.

Allowance for Funds Used During Construction (AFUDC)

AFUDC is a noncash nonoperating income item that is capitalized and recovered through depreciation over the service life of utility plant. It represents the estimated cost of borrowed and equity funds used to finance construction projects. The amounts of AFUDC for 1998, 1997 and 1996 were not significant.

Depreciation and Amortization

Depreciation of electric utility plant is provided on a straight-line basis over the estimated useful lives of utility plant and is calculated largely through the use of composite rates by functional class. The annual composite depreciation rates for 1998, 1997 and 1996 are as follows:

Functional Class of Property	Annual Composite Depreciation Rates		
	1998	1997	1996
Production:			
Steam-Nuclear	3.4%	3.4%	3.4%
Steam-Fossil-Fired	4.4%	4.4%	4.4%
Hydroelectric-Conventional	3.4%	3.2%	3.2%
Transmission	1.9%	1.9%	1.9%
Distribution	4.2%	4.2%	4.2%
General	3.8%	3.8%	3.8%

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

Cash and Cash Equivalents

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

Operating Revenues and Fuel Costs

Revenues include the accrual of electricity consumed but unbilled at month-end as well as billed revenues. Fuel costs are matched with revenues in accordance with rate commission orders. Revenues are accrued related to unrecovered fuel in both state retail jurisdictions and for replacement power costs in the Michigan jurisdiction until approved for billing. If the Company's earnings exceed the allowed return in the Indiana jurisdiction, the fuel clause mechanism provides for the refunding of the excess earnings to ratepayers. FERC wholesale jurisdictional fuel cost changes are expensed and billed as incurred.

Derivative Financial Instruments

During 1998, the AEP Power Pool substantially increased the volume of its power marketing and trading transactions (trading activities) in which the Company shares. Trading activities involve the sale of electricity under physical forward contracts at fixed and variable prices and the trading of electricity contracts including exchange traded futures and options and over-the-counter options and swaps. The majority of these transactions represent physical forward contracts

in the AEP System's traditional marketing area and are typically settled by entering into offsetting contracts. The net revenues from these transactions are included in operating revenues for ratemaking, accounting and financial and regulatory reporting purposes.

In addition the AEP Power Pool enters into transactions for the purchase and sale of electricity options, futures and swaps, and for the forward purchase and sale of electricity outside of the AEP Power Pool's traditional marketing area. These non-regulated trading activities are included in nonoperating income and accounted for on a mark-to-market basis. The unrealized mark-to-market gains and losses from such non-regulated trading activity are reported as assets and liabilities, respectively.

The Company enters into forward contracts to manage the exposure to unfavorable changes in the cost of debt to be issued. These anticipatory debt instruments are entered into in order to manage the change in interest rates between the time a debt offering is initiated and the issuance of the debt (usually a period of 60 days). Any resultant gains or losses are deferred and amortized over the life of the debt issuance. There were no such forward contracts outstanding at December 31, 1998 or 1997.

See Note 7 - Financial Instruments, Credit and Risk Management for further discussion.

Reclassification

In the fourth quarter of 1998 the Company changed the presentation of its trading activities from a gross basis (purchases and sales reported separately) to a net basis (purchases and sales are reported on a net basis as revenues). This reclassification had no impact on net income. Certain prior year amounts have been reclassified to conform to current year presentation. Such reclassifications had no impact on previously reported net income.

Levelization of Nuclear Refueling Outage Costs

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

Income Taxes

The Company follows the liability method of accounting for income taxes as prescribed by SFAS 109, "Accounting for Income Taxes." Under the liability method, deferred income taxes are provided for all temporary differences between the book cost and tax basis of assets and liabilities which will result in a future tax consequence. Where the flow-through method of accounting for temporary differences is reflected in rates, deferred income taxes are provided with related regulatory assets and liabilities in accordance with SFAS 71.

Investment Tax Credits

Investment tax credits have been accounted for under the flow-through method except where regulatory commissions have reflected investment tax credits in the rate-making process on a deferral basis. Investment tax credits that have been deferred are being amortized over the life of regulated plant investment.

Debt and Preferred Stock

Gains and losses from the reacquisition of debt are deferred as

regulatory assets and amortized over the remaining term of the reacquired debt in accordance with rate-making treatment. If the debt is refinanced the reacquisition costs are deferred and amortized over the term of the replacement debt commensurate with their recovery in rates.

Debt discount or premium and debt issuance expenses are deferred and amortized over the term of the related debt, with the amortization included in interest charges.

Redemption premiums paid to reacquire preferred stock are included in paid-in capital and amortized to retained earnings commensurate with their recovery in rates. The excess of par value over the cost of preferred stock reacquired is credited to paid-in capital and amortized to retained earnings.

Nuclear Decommissioning and Spent Nuclear Fuel Disposal Trust Funds

Securities held in trust funds for decommissioning nuclear facilities and for the disposal of spent nuclear fuel (SNF) are recorded at market value in accordance with SFAS 115, "Accounting for Certain Investments in Debt and Equity Securities." Securities in the trust funds have been classified as available-for-sale due to their long-term purpose. Due to the rate-making process, adjustments for unrealized gains and losses are not reported in equity but result in adjustments to the liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the SNF disposal trust funds.

Other Property and Investments

Other property and investments are stated at cost.

Comprehensive Income

There were no material differences between net income and comprehensive income.

2. <u>EFFECTS OF REGULATION AND PHASE-IN PLANS</u>:

In accordance with SFAS 71 the consolidated financial statements include regulatory assets (deferred expenses) and regulatory liabilities (deferred income) recorded in accordance with regulatory actions in order to match expenses and revenues from cost-based rates in the same accounting period. Regulatory assets are expected to be recovered in future periods through the rate-making process and regulatory liabilities are expected to reduce future cost recoveries. Among other things, application of SFAS 71 requires that the Company's regulated rates be cost-based and recovery of regulatory assets must be probable. Management has reviewed the evidence currently available and concluded that the Company continues to meet the requirements to apply SFAS 71. In the event a portion of the Company's business no longer met these requirements, that is, its rates were no longer cost-based, regulatory assets and liabilities would have to be written off for that portion of the business and tangible assets would have to be tested for possible impairment and if required an impairment loss recorded unless the net regulatory assets and impairment losses are recoverable as a stranded cost.

Recognized regulatory assets and liabilities are comprised of the following:

	December 31, 1998	December 31, 1997
	(in thousands)	
Regulatory Assets:		
Amounts Due From Customers for Future Income Taxes	$259,641	$277,966
Unrecovered Fuel and Purchased Power	65,308	18,462
Department of Energy Decontamination and Decommissioning Assessment	38,898	42,648
Nuclear Refueling Outage Cost Levelization	17,630	31,772
Unamortized Loss On Reacquired Debt	16,434	17,210
Other	23,564	12,431
Total Regulatory Asset	$421,475	$400,489
Regulatory Liabilities:		
Deferred Investment Tax Credits	$129,779	$138,045
Other*	16,507	1,262
Total Regulatory Liabilities	$146,286	$139,307

* Included in Deferred Credits on Consolidated Balance Sheets.

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

At January 1, 1997 rate phase-in plan deferrals existed for the Rockport Plant. Rate phase-in plans in the Company's Indiana and FERC jurisdictions provided for the recovery and straight-line amortization of deferred Rockport Plant Unit 1 costs over ten years beginning in 1987. In 1997 the amortization and recovery of the deferred Rockport Plant Unit 1 Phase-in Plan costs were completed. During the recovery period net income was unaffected by the recovery of the phase-in deferrals. Amortization was $11.9 million in 1997 and $15.6 million in 1996.

3. COMMITMENTS AND CONTINGENCIES:

Construction and Other Commitments

Substantial construction commitments have been made to support the Company's utility operations including the replacement of the Cook Plant Unit 1 steam generators. Such commitments do not include any expenditures for new generating capacity. Construction program expenditures for 1999-2001 are estimated to be $366 million.

Long-term fuel supply contracts contain clauses that provide for periodic price adjustments. The retail jurisdictions have fuel clause mechanisms that provide for recovery of changes in the cost of fuel with the regulators' review and approval. See Note 4 for changes in the fuel clause mechanism in the Indiana jurisdiction proposed in a settlement agreement. The contracts are for various terms, the longest of which extends to 2014, and contain various clauses that would release the Company from its obligation under certain force majeure conditions.

The Company is committed under unit power agreements to purchase all of an affiliate's share, 50% of the 2,600 mw Rockport Plant capacity, unless it is sold to other utilities. The affiliate has a long-term unit power agreement for the sale of 455 mw to an unaffiliated utility. Revenues received under this agreement (which expires at the end of 1999) were $70 million in 1998. An agreement between the affiliate which owns Rockport Plant and another affiliate provides for the sales of 390 mw of capacity to that affiliate through 2004.

The Company sells under contract up to 250 mw of its Rockport Plant capacity to an unaffiliated utility. The contract expires in 2009.

Nuclear Plant

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

Nuclear Plant Shutdown

I&M shut down both units of the Cook Plant in September 1997 due to questions, which arose during a NRC architect engineer design inspection, regarding the operability of certain safety systems. The NRC issued a Confirmatory Action Letter in September 1997 requiring I&M to address the issues identified in the letter. I&M is working with the NRC to resolve the remaining open issue in the letter.

In April 1998 the NRC notified I&M that it had convened a Restart Panel for Cook Plant. A list of required restart activities was provided by the NRC in July 1998 and in October the NRC expanded the list. In order to identify and resolve the issues necessary to restart the Cook units, I&M is and will be meeting with the Panel on a regular basis, until the units are returned to service.

In January 1999 I&M announced that it will conduct additional engineering reviews at the Cook Plant that will delay restart of the units. Previously, the units were scheduled to return to service at the end of the first and second quarters of 1999. The decision to delay restart resulted from internal assessments that indicated a need to conduct expanded system readiness reviews. A new restart schedule will be developed based on the results of the expanded reviews and should be available in June 1999. When maintenance and other activities required for restart are complete, I&M will seek concurrence from the NRC to return the Cook Plant to service. Until these additional reviews are completed, management is unable to determine when the units will be returned to service. Unless the costs of the extended outage and restart efforts are recovered from customers, there would be a material adverse effect on results of operations, cash flows and possibly financial condition.

The costs incurred in 1997 and 1998 for restart of the Cook units were $6 million and $78 million, respectively, and were recorded as operation and maintenance expense. Reductions in other operation and maintenance expenses partially offset these costs. Currently incremental restart expenses are approximately $12 million a month.

In July 1998 I&M received an "adverse trend letter" from the NRC indicating that NRC senior managers determined that there had been a slow decline in performance at the Cook Plant during the 18 month period preceding the letter. The letter indicated that the NRC will closely monitor efforts to address issues at Cook Plant through additional inspection activities. In October

1998 the NRC issued I&M a Notice of Violation and proposed a $500,000 civil penalty for alleged violations at the Cook Plant discovered during five inspections conducted between August 1997 and April 1998. I&M paid the penalty.

The cost of electricity supplied to certain retail customers rose due to the extended outage since higher cost coal-fired generation and coal based purchased power were substituted for low cost nuclear generation. I&M's Indiana and Michigan retail jurisdictional fuel cost recovery mechanisms permit the recovery, subject to regulatory commission review and approval, of changes in fuel costs including the fuel component of purchased power in the Indiana jurisdiction and changes in replacement power in the Michigan jurisdiction. The IURC approved, subject to future reconciliation or refund, agreements authorizing I&M, during the billing months of July 1998 through March 1999, to include in rates a fuel cost adjustment factor less than that requested by I&M. The agreements provide the parties to the proceedings with the opportunity to conduct discovery regarding certain issues that were raised in the proceedings, including the appropriateness of the recovery of replacement energy cost due to the extended Cook Plant outage, in anticipation of resolving the issues in a future fuel cost adjustment proceeding. A regulatory asset in the amount of $65 million of replacement energy costs has been recorded at December 31, 1998. See Note 4 for discussion of proposed settlement agreement for the Indiana jurisdiction.

Historically, the Company has been permitted to recover through the fuel recovery mechanism the cost of replacement energy during outages. Management believes that it should be allowed to recover the deferred Cook replacement energy costs; however, if recovery of the replacement costs is denied, future results of operations and cash flows would be adversely affected by the writeoff of the regulatory asset.

Nuclear Incident Liability

Public liability is limited by law to $9 billion should an incident occur at any licensed reactor in the US. Commercially available insurance provides $200 million of coverage. In the event of a nuclear incident at any nuclear plant in the US the remainder of the liability would be provided by a deferred premium assessment of $88 million on each licensed reactor payable in annual installments of $10 million. As a result, I&M could be assessed $176 million per nuclear incident payable in annual installments of $20 million. The number of incidents for which payments could be required is not limited.

Nuclear insurance pools and other insurance policies provide $3 billion of property damage, decommissioning and decontamination coverage for Cook Plant. Additional insurance provides coverage for extra costs resulting from a prolonged accidental Cook Plant outage. Some of the policies have deferred premium provisions which could be triggered by losses in excess of the insurer's resources. The losses could result from claims at the Cook Plant or certain other unaffiliated nuclear units. The Company could be assessed up to $23.2 million annually under these policies.

SNF Disposal

Federal law provides for government responsibility for permanent SNF disposal and assesses nuclear plant owners fees for SNF disposal. A fee of one mill per kilowatthour for fuel consumed after April 6, 1983 is being collected from customers and remitted to the US

Treasury. Fees and related interest of $190 million for fuel consumed prior to April 7, 1983 have been recorded as long-term debt. I&M has not paid the government the pre-April 1983 fees due to continued delays and uncertainties related to the federal disposal program. At December 31, 1998, funds collected from customers towards payment of the pre-April 1983 fee and related earnings thereon approximate the liability.

Decommissioning and Low Level Waste Accumulation Disposal

Decommissioning costs are being accrued over the service life of the Cook Plant. The licenses to operate the two nuclear units expire in 2014 and 2017. After expiration of the licenses the plant is expected to be decommissioned through dismantlement. The estimated cost of decommissioning and low level radioactive waste accumulation disposal costs ranges from $700 million to $1,152 million in 1997 nondiscounted dollars. The wide range is caused by variables in assumptions including the estimated length of time SNF may need to be stored at the plant site subsequent to ceasing operations. This, in turn, depends on future developments in the federal government's SNF disposal program. Continued delays in the federal fuel disposal program can result in increased decommissioning costs. The Company is recovering estimated decommissioning costs in its three rate-making jurisdictions based on at least the lower end of the range in the most recent decommissioning study at the time of the last rate proceeding. The Company records decommissioning costs in other operation expense and records a noncurrent liability equal to the decommissioning cost recovered in rates; such amount was $29 million in 1998, $28 million in 1997 and $27 million in 1996. Decommissioning costs recovered from customers are deposited in external trusts, which are described in Note 7. Trust fund earnings increase the fund assets and the recorded liability and decrease the amount needed to be recovered from ratepayers. During 1998 the Company withdrew $3 million from the trust funds and expects to withdraw $8 million in 1999 for decommissioning the original steam generators removed from Unit 2. At December 31, 1998 and 1997, the Company has recognized a decommissioning liability of $446 million and $381 million, respectively.

Air Quality

On September 24, 1998, the US Environmental Protection Agency (Federal EPA) finalized rules which require reductions in nitrogen oxides (NOx) emissions in 22 eastern states, including the states in which the generating plants of the Company and its AEP Power Pool affiliates are located. The implementation of the final rules would be achieved through the revision of state implementation plans (SIPs) by September 1999. SIPs are a procedural method used by each state to comply with Federal EPA rules. The final rules anticipate the imposition of a NOx reduction on utility sources of approximately 85% below 1990 emission levels by the year 2003. On October 30, 1998, a number of utilities, including the Company and the other operating companies of the AEP System, filed petitions in the US Court of Appeals for the District of Columbia Circuit seeking a review of the final rules.

Should the states fail to adopt the required revisions to their SIPs within one year of the date of the final rules (September 24, 1999), Federal EPA has proposed to implement a federal plan to accomplish the NOx reductions. Federal EPA also proposed the approval of portions of petitions filed by eight northeastern states that would result in imposition of NOx emission reductions on utility and industrial sources in

upwind midwestern states. These reductions are substantially the same as those required by the final NOx rules and could be adopted by Federal EPA in the event the states fail to implement SIPs in accordance with the final rules.

Preliminary estimates indicate that compliance could result in required capital expenditures of approximately $169 million. Compliance costs cannot be estimated with certainty and the actual costs incurred to comply could be significantly different from this preliminary estimate depending upon the compliance alternatives selected to achieve reductions in NOx emissions. Unless such costs are recovered from customers, they would have a material adverse effect on results of operations, cash flows and possibly financial condition.

Litigation

The Internal Revenue Service (IRS) agents auditing the AEP System's consolidated federal income tax returns for the years 1991 to 1993 requested a ruling from their National Office that certain interest deductions claimed by the Company relating to a corporate owned life insurance (COLI) program should not be allowed. As a result of a suit filed by the Company in US District Court (discussed below) the request for ruling was withdrawn by the IRS agents. Adjustments have been or will be proposed by the IRS disallowing COLI interest deductions for taxable years 1991-96. A disallowance of the COLI interest deductions through December 31, 1998 would reduce earnings by approximately $66 million (including interest). The Company has made no provision for any possible adverse earnings impact from this matter.

In 1998 the Company made payments of taxes and interest attributable to COLI interest deductions for taxable years 1991-97 to avoid the potential assessment by the IRS of any additional above market rate interest on the contested amount. The payments to the IRS are included on the balance sheet in other property and investments pending the resolution of this matter. The Company will seek refund, either administratively or through litigation, of all amounts paid plus interest. In order to resolve this issue without further delay, on March 24, 1998, the Company filed suit against the US in the US District Court for the Southern District of Ohio. Management believes that it has a meritorious position and will vigorously pursue this lawsuit. In the event the resolution of this matter is unfavorable, it will have a material adverse impact on results of operations and cash flows.

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

4. <u>SUBSEQUENT EVENT - SETTLEMENT AGREEMENT (MARCH 16, 1999)</u>:

On March 16, 1999 a settlement agreement was filed with the IURC resolving all matters related to the reasonableness of fuel costs and all outage issues during an extended outage of the Cook Plant. The settlement agreement, which is subject to IURC approval, provides for, among other things, a credit of $55 million to Indiana retail customers; authorization to defer any unrecovered fuel revenues accrued between September 9, 1997 and December 31, 1999 including the $55 million; authorization to defer up to $150 million of incremental operation

and maintenance restart costs for the Cook Plant above the base rate level incurred during 1999; amortization of the fuel recoveries and restart cost deferrals over a five-year period ending December 31, 2003; a freeze in base rates though December 31, 2003; and a cap on fuel recovery charges through March 1, 2004. The $55 million credit will be refunded through customer's bills during the months of July, August and September 1999. If the IURC does not approve the settlement, the issue of recovery of replacement energy costs would be resolved through regulatory hearings. Unless the costs of the extended outage and restart efforts are recovered from customers, there would be a material adverse effect on results of operations, cash flows, and possibly financial condition.

5. RELATED PARTY TRANSACTIONS:

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

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

	Year Ended December 31,		
	1998	1997	1996
	(in thousands)		
Capacity Revenues	$33,011	$ 53,282	$ 57,594
Energy Revenues	4,550	64,861	98,162
Total	$37,561	$118,143	$155,756

Purchased power expense includes charges of $125.2 million in 1998, $51 million in 1997 and $34.5 million in 1996 for energy received from the AEP Power Pool.

Power marketing and trading operations, which are described in Note 1, are conducted by the AEP Power Pool and shared with the Company. The Company's operating revenues, purchased power expense and nonoperating income include amounts for power marketing and trading allocated by the AEP Power Pool as follows:

	Year Ended December 31,		
	1998	1997	1996
	(in thousands)		
Operating Revenues	$124,973	$74,895	$73,424
Purchased Power Expense	71,588	15,415	8,098
Nonoperating Loss	(7,122)	(61)	-

The cost of Rockport Plant power purchased from AEGCo, an affiliated company that is not a member of the AEP Power Pool, was included in purchased power expense in the amounts of $86.2 million, $87.5 million and $85.4 million in 1998, 1997 and 1996, respectively.

The cost of power purchased from Ohio Valley Electric Corporation, an affiliated company that is not a member of the AEP Power Pool, was included in purchased power expense in the amounts of $14.3 million, $11 million and $10.7 million in 1998, 1997 and 1996, respectively.

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

AEP System companies participate in the AEP System Transmission Equalization Agreement. This agreement combines certain AEP System companies' investments in transmission facilities and shares the costs of ownership in proportion to the AEP System companies' respective peak demands. Pursuant to the terms of the agreement, since the Company's relative investment in transmission facilities is greater than its relative peak demand, other operation expense includes equalization credits of $44.1 million, $46.1 million and $46.3 million in 1998, 1997 and 1996, respectively.

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

	Year Ended December 31,		
	1998	1997	1996
	(in thousands)		
Affiliated Companies	$23,494	$24,427	$22,740
Unaffiliated Companies	12,490	8,383	6,776
Total	$35,984	$32,810	$29,516

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

6. SEGMENT INFORMATION:

Effective December 31, 1998 the Company adopted SFAS 131, "Disclosures about Segments of an Enterprise and Related Information". The Company has one reportable segment, a regulated vertically integrated electricity generation and energy delivery business. All other activities are insignificant. The Company's operations are managed on an integrated basis because of the substantial impact of bundled cost-based rates and regulatory oversight on business processes, cost structures and operating results. Aggregated in the regulated electric utility segment is the power marketing and trading activities that are discussed in Note 1 and the Company's barging activities. For the years ended December 31, 1998, 1997 and 1996, all revenues are derived in the US.

7. FINANCIAL INSTRUMENTS, CREDIT AND RISK MANAGEMENT:

The Company is subject to market risk as a result of changes in electricity commodity prices and interest rates. The Company participates in the AEP Power Pool's power marketing and trading operation that manages the exposure to electricity commodity price movements using physical forward purchase and sale contracts at fixed and variable prices, and financial derivative instruments including exchange traded futures and options, over-the-counter options, swaps and other financial derivative contracts at both fixed and variable prices. Physical forward electricity contracts within the AEP Power Pool's traditional marketing area are recorded on a net basis as operating revenues in the month when the physical contract settles. The Company's share of the net gains from these regulated transactions for the year ended December 31, 1998 was $21 million.

Physical forward electricity contracts outside the AEP Power Pool's traditional marketing area and all financial electricity trading transactions including exchange traded contracts that are marked to market and recorded in nonoperating income. The Company's share of the net losses from these non-regulated trading transactions for the year ended December 31, 1998 was $7 million. The unrealized mark-to-market gains and losses from such trading of financial instruments are reported as assets and liabilities, respectively. These activities were not material in prior periods.

The Company is exposed to risk from changes in interest rates primarily due to short-term and long-term borrowings used to fund its business operations. The debt portfolio has both fixed and variable interest rates with terms from one day to forty years and an average duration of six years at December 31, 1998. A near term change in interest rates should not materially affect results of operations or financial position since the Company would not expect to liquidate its entire debt portfolio in a one year holding period. Also since the Company's rates are cost-based regulated, the risk of interest rate changes on debt used to finance regulated operations is mitigated.

Market Valuation

The book value of cash and cash equivalents, accounts receivable, short-term debt and accounts payable approximate fair value because of the short-term maturity of these instruments. The book value of the pre-April 1983 spent nuclear fuel disposal liability approximates the Company's best estimate of its fair value.

The book value amounts and fair values of the Company's share of significant financial instruments at December 31, 1998 and 1997 are summarized in the following table. The fair values of long-term debt and preferred stock are based on quoted market prices for the same or similar issues and the current dividend or interest rates offered for instruments of the same remaining maturities. The fair value of those financial instruments that are marked-to-market are based on management's best estimates using over-the-counter quotations, exchange prices, volatility factors and valuation methodology. The estimates presented herein are not necessarily indicative of the amounts that the Company could realize in a current market exchange. At December 31, 1997 the notional amounts and fair values of derivatives were not material.

	Book Value	Fair Value
	(in thousands)	
Non-Derivatives		
1998		
Long-term Debt	$1,175,800	$1,235,200
Preferred Stock	68,400	72,600
1997		
Long-term Debt	1,049,200	1,094,100
Preferred Stock	68,400	73,300
Derivatives		
1998		

	Fair Value	Average Fair Value
	(in thousands)	
Trading Assets		
Electric		
Physicals	$8,700	$ 7,700
Options	6,300	15,300
Swaps	600	200
Trading Liabilities		
Electric		
Futures	(1,300)	(300)
Physicals	(9,400)	(8,800)
Options	(5,700)	(15,200)
Swaps	(1,400)	(400)

At December 31, 1998 the notional amounts of the Company's nonregulated electric trading physical forward contract purchases and sales are 1,912 Gigawatt hours

(Gwh) and 2,044 Gwh, respectively; the notional amounts for fixed priced swaps purchases and sales are 70 Gwh and 75 Gwh, respectively; and the notional amounts for options to purchase and to sell are 1,381 Gwh and 992 Gwh, respectively. The Company has a net long position of 74 Gwh for electric future contracts.

At December 31, 1998 the fair value of the assets and liabilities related to the wholesale electric forward contracts was $69 million and $67 million, respectively. The related notional amounts were 9,094 Gwh for purchases and 9,280 Gwh for sales. The average fair value amounts outstanding during the period were $175 million of assets and $167 million of liabilities.

Credit and Risk Management

In addition to market risk associated with price movements, the Company through the AEP Power Pool is also subject to the credit risk inherent in its risk management activities. Credit risk refers to the financial risk arising from commercial transactions and/or the intrinsic financial value of contractual agreements with trading counter parties, by which there exists a potential risk of nonperformance. The AEP Power Pool has established and enforced credit policies that minimize this risk. The AEP Power Pool accepts as counter parties to forwards, futures, and other derivative contracts primarily those entities that are classified as Investment Grade, or those that can be considered as such due to the effective placement of credit enhancements and/or collateral agreements. Investment grade is the designation given to the four highest debt rating categories (i.e., AAA, AA, A, BBB) of the major rating services, e.g., ratings BBB- and above at Standard & Poor's and Baa3 and above at Moody's. When adverse market conditions have the potential to negatively affect a counter party's credit position, the AEP Power Pool requires further credit enhancements to mitigate risk. Since the formation of the power marketing and trading business in July of 1997, the Company has experienced no significant losses due to the credit risk associated with risk management activities; furthermore, the Company does not anticipate any future material effect on its results of operations, cash flow or financial condition as a result of counter party nonperformance.

Nuclear Trust Funds Recorded at Market Value

The Nuclear Decommissioning and Spent Nuclear Fuel Disposal Trust Fund investments are recorded at market value in accordance with SFAS 115 and consist of tax-exempt municipal bonds and other securities.

At December 31, 1998 and 1997 the fair values of trust fund investments were $648 million and $566 million, respectively. Accumulated gross unrealized holding gains were $65 million and $41 million and accumulated gross unrealized holding losses were $1.1 million and $1.2 million at December 31, 1998 and 1997, respectively. The change in market value in 1998, 1997 and 1996 was a net unrealized holding gain of $24 million, $19.1 million and $2.6 million, respectively.

The trust fund investments' cost basis by security type were:

	December 31,	
	1998	1997
	(in thousands)	
Tax-Exempt Bonds	$326,239	$335,358
Equity Securities	95,854	74,398
Treasury Bonds	71,194	44,200
Corporate Bonds	10,661	9,167
Cash, Cash Equivalents and Interest Accrued	80,065	63,392
Total	$584,013	$526,515

Proceeds from sales and maturities of securities of $225 million during 1998 resulted in $8.2

million of realized gains and $2.8 million of realized losses. Proceeds from sales and maturities of securities of $147.3 million during 1997 resulted in $3.9 million of realized gains and $1.4 million of realized losses. Proceeds from sales and maturities of securities of $115.3 million during 1996 resulted in $2.6 million of realized gains and $2.1 million of realized losses. The cost of securities for determining realized gains and losses is original acquisition cost including amortized premiums and discounts.

At December 31, 1998, the year of maturity of trust fund investments, other than equity securities, was:

	(in thousands)
1999	$106,316
2000-2003	157,224
2004-2008	175,751
After 2008	48,868
Total	$488,159

8. STAFF REDUCTIONS:

During 1998 an internal evaluation of the power generation organization was conducted with a goal of developing a better organizational structure for a competitive generation market. The study was completed in October 1998. In addition, a review of energy delivery staffing levels was conducted in 1998. As a result approximately 80 power generation and energy delivery positions were identified for elimination.

Severance accruals totaling $3.7 million were recorded in December 1998 for reductions in power generation and energy delivery staffs and were charged to other operation expense in the Consolidated Statements of Income. In the first quarter of 1999 the power generation and energy delivery staff reductions were made.

9. BENEFIT PLANS:

The Company and its subsidiaries participate in the AEP System qualified pension plan, a defined benefit plan which covers all employees. Net pension costs for the years ended December 31, 1998, 1997 and 1996 were $2.1 million, $2.1 million and $4.1 million, respectively.

Postretirement benefits other than pensions are provided for retired employees for medical and death benefits under an AEP System plan. The Company's annual accrued costs for 1998, 1997 and 1996 were $12 million, $11.5 million and $12.8 million, respectively.

A defined contribution employee savings plan required that the Company make contributions to the plan totaling $4 million in 1998 and 1997 and $3.7 million in 1996.

10. FEDERAL INCOME TAXES:

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

	Year Ended December 31, 1998	1997 (in thousands)	1996
Charged (Credited) to Operating Expenses (net):			
Current	$ 38,165	$ 75,442	$110,133
Deferred	21,073	3,088	(24,730)
Deferred Investment Tax Credits	(7,593)	(7,786)	(7,874)
Total	51,645	70,744	77,529
Charged (Credited) to Nonoperating Income (net):			
Current	(594)	3,287	182
Deferred	(3,168)	834	43
Deferred Investment Tax Credits	(673)	(642)	(855)
Total	(4,435)	3,479	(630)
Total Federal Income Taxes as Reported	$ 47,210	$ 74,223	$ 76,899

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, 1998	1997 (in thousands)	1996
Net Income	$ 96,628	$146,740	$157,153
Federal Income Taxes	47,210	74,223	76,899
Pre-tax Book Income	$143,838	$220,963	$234,052
Federal Income Tax on Pre-tax Book Income at Statutory Rate (35%)	$50,343	$77,337	$81,918
Increase (Decrease) in Federal Income Tax Resulting From the Following Items:			
Depreciation	17,257	14,082	13,880
Corporate Owned Life Insurance	(3,263)	(3,348)	(2,178)
Nuclear Fuel Disposal Costs	(3,397)	(3,286)	(3,096)
Investment Tax Credits (net)	(8,266)	(8,428)	(8,729)
Other	(5,464)	(2,134)	(4,896)
Total Federal Income Taxes as Reported	$47,210	$74,223	$76,899
Effective Federal Income Tax Rate	32.8%	33.6%	32.9%

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

	December 31, 1998	1997 (in thousands)
Deferred Tax Assets	$ 226,118	$ 223,772
Deferred Tax Liabilities	(785,406)	(783,480)
Net Deferred Tax Liabilities	$(559,288)	$(559,708)
Property Related Temporary Differences	$(460,077)	$(471,898)
Amounts Due From Customers For Future Federal Income Taxes	(69,102)	(74,282)
Deferred State Income Taxes	(62,302)	(65,679)
Deferred Gain on Sale and Leaseback of Rockport Plant Unit 2	31,049	32,347
Accrued Nuclear Decommissioning Expense	29,930	26,991
All Other (net)	(28,786)	(7,187)
Net Deferred Tax Liabilities	$(559,288)	$(559,708)

The Company and its subsidiaries join in the filing of a consolidated federal income tax return with their affiliates in the AEP System. The allocation of the AEP System's current consolidated federal income tax to the AEP System companies is in accordance with SEC rules under the 1935 Act. These rules permit the allocation of the benefit of current tax losses to the System companies giving rise to them in determining their current tax expense. The tax loss of the parent company, AEP Co., Inc., is allocated to its subsidiaries with taxable income. With the exception of the loss of the parent company, the method of allocation approximates a separate return result for each company in the consolidated group.

The AEP System has settled with the IRS all issues from the audits of the consolidated federal income tax returns for the years prior to 1991. Returns for the years 1991 through 1996 are presently being audited by the IRS. With the exception of interest deductions related to COLI, which are discussed under the heading, Litigation, in Note 3, management is not aware of any issues for open tax years that upon final resolution are expected to have a material adverse effect on results of operations.

11. COMMON SHAREHOLDER'S EQUITY:

Mortgage indentures, charter provisions and orders of regulatory authorities place various restrictions on the use of retained earnings for the payment of cash dividends on common stock. At December 31, 1998, $5.9 million of retained earnings were restricted. Regulatory approval is required to pay dividends out of paid-in capital.

In 1998, 1997 and 1996 net changes to paid-in capital of $133,000, $1,200,000 and $170,000 respectively, represented gains and expenses associated with cumulative preferred stock transactions.

12. SUPPLEMENTARY INFORMATION:

	Year Ended December 31,		
	1998	1997	1996
	(in thousands)		
Cash was paid for:			
Interest (net of capitalized amounts)	$66,313	$ 62,274	$ 64,117
Income Taxes	36,413	120,212	125,707
Noncash Acquisitions Under Capital Leases	9,658	111,395	48,305

In connection with the 1996 early termination of a western coal land sublease the Company will receive cash payments from the lessee of $30.8 million over a ten-year period which was recorded at a net present value of $22.8 million. The long-term portion of this receivable is recorded as other property and investments and the current portion is recorded as miscellaneous accounts receivable.

13. CUMULATIVE PREFERRED STOCK:

At December 31, 1998, authorized shares of cumulative preferred stock were as follows:

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

The cumulative preferred stock is callable at the price indicated below plus accrued dividends. The involuntary liquidation preference is par value. Unissued shares of the cumulative preferred stock may or may not possess mandatory redemption characteristics upon issuance. During 1996 the Company redeemed and canceled 300,000 shares of the 7.08% series not subject to mandatory redemption.

A. Cumulative Preferred Stock Not Subject to Mandatory Redemption:

Series	Call Price December 31, 1998	Par Value	Number of Shares Redeemed Year Ended December 31, 1998	1997	1996	Shares Outstanding December 31, 1998	Amount December 31, 1998	1997
							(in thousands)	
4-1/8%	$106.125	$100	771	59,760	233	59,236	$5,924	$6,001
4.56%	102	100	650	44,788	-	14,562	1,456	1,521
4.12%	102.728	100	200	20,869	-	18,931	1,893	1,913
							$9,273	$9,435

B. Cumulative Preferred Stock Subject to Mandatory Redemption:

Series(a)	Par Value	Number of Shares Redeemed Year Ended December 31, 1998	1997	1996	Shares Outstanding December 31, 1998	Amount December 31, 1998	1997
						(in thousands)	
5.90% (b)	$100	-	233,000	-	167,000	$16,700	$16,700
6-1/4%(b)	100	-	97,500	-	202,500	20,250	20,250
6.30% (b)	100	-	217,550	-	132,450	13,245	13,245
6-7/8%(c)	100	-	117,500	-	182,500	18,250	18,250
						$68,445	$68,445

(a) Not callable until after 2002. There are no aggregate sinking fund provisions through 2002. A sinking fund provision requires the redemption of 15,000 shares in 2003.
(b) Commencing in 2004 and continuing through 2008 the Company may redeem, at $100 per share, 20,000 shares of the 5.90% series, 15,000 shares of the 6-1/4% series and 17,500 shares of the 6.30% series outstanding under sinking fund provisions at its option and all remaining outstanding shares must be redeemed not later than 2009. Shares redeemed in 1997 may be applied to meet the sinking fund requirement.
(c) Commencing in 2003 and continuing through the year 2007, a sinking fund will require the redemption of 15,000 shares each year and the redemption of the remaining shares outstanding on April 1, 2008, in each case at $100 per share. Shares redeemed in 1997 may be applied to meet the sinking fund requirement.

14. LONG-TERM DEBT AND LINES OF CREDIT:

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

	December 31, 1998	December 31, 1997
	(in thousands)	
First Mortgage Bonds	$ 466,330	$ 520,317
Installment Purchase Contracts	309,418	309,269
Senior Unsecured Notes	48,559	-
Other Long-term Debt (a)	190,192	180,837
Junior Debentures	161,290	38,814
	1,175,789	1,049,237
Less Portion Due Within One Year	35,000	35,000
Total	$1,140,789	$1,014,237

(a) Represents a SNF disposal liability including interest accrued payable to the Department of Energy. See Note 3.

First mortgage bonds outstanding were as follows:

% Rate	Due	December 31, 1998	December 31, 1997
		(in thousands)	
7.00	1998 - May 1	$ -	$ 35,000
7.30	1999 - December 15	35,000	35,000
6.40	2000 - March 1	48,000	48,000
7.63	2001 - June 1	40,000	40,000
7.60	2002 - November 1	50,000	50,000
7.70	2002 - December 15	40,000	40,000
6.80	2003 - July 1	20,000	20,000
6.55	2003 - October 1	20,000	20,000
6.10	2003 - November 1	30,000	30,000
6.55	2004 - March 1	25,000	25,000
8.50	2022 - December 15	75,000	75,000
7.80	2023 - July 1	-	20,000
7.35	2023 - October 1	20,000	20,000
7.20	2024 - February 1	40,000	40,000
7.50	2024 - March 1	25,000	25,000
Unamortized Discount (net)		(1,670)	(2,683)
		466,330	520,317
Less Portion Due Within One Year		35,000	35,000
Total		$431,330	$485,317

Certain indentures relating to the first mortgage bonds contain improvement, maintenance and replacement provisions requiring the deposit of cash or bonds with the trustee, or in lieu thereof, certification of unfunded property additions.

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

% Rate	Due	December 31, 1998	December 31, 1997
		(in thousands)	
City of Lawrenceburg, Indiana:			
7.00	2015 - April 1	$ 25,000	$ 25,000
5.90	2019 - November 1	52,000	52,000
City of Rockport, Indiana:			
(a)	2014 - August 1	50,000	50,000
7.60	2016 - March 1	40,000	40,000
6.55	2025 - June 1	50,000	50,000
(b)	2025 - June 1	50,000	50,000
City of Sullivan, Indiana:			
5.95	2009 - May 1	45,000	45,000
Unamortized Discount		(2,582)	(2,731)
Total		$309,418	$309,269

(a) A variable interest rate is determined weekly. The average weighted interest rate was 4.1% for 1998 and 4.3% for 1997.

(b) An adjustable interest rate can be a daily, weekly, commercial paper or term rate as designated by the Company. A weekly rate was selected which ranged from 2.7% to 4.3% in 1998 and from 3.0% to 4.6% in 1997 and averaged 3.6% and 3.8% during 1998 and 1997, respectively.

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

expires in 2000. Accordingly, the variable and adjustable rate installment purchase contracts have been classified for repayment purposes based on the expiration dates of the standby purchase agreement and the letter of credit.

In November 1998 the Company issued $50,000,000 of 6.45% senior unsecured notes due November 10, 2008. The unamortized discount at December 31, 1998 was $1,441,000.

Junior debentures are composed of the following:

% Rate	Due	December 31, 1998 (in thousands)	December 31, 1997 (in thousands)
8.00	2026 - March 31	$ 40,000	$40,000
7.60	2038 - June 30	125,000	-
Unamortized Discount		(3,710)	(1,186)
Total		$161,290	$38,814

Interest may be deferred and payment of principal and interest on the junior debentures is subordinated and subject in right to the prior payment in full of all senior indebtedness of the Company.

At December 31, 1998, future annual long-term debt payments are as follows:

	Amount (in thousands)
1999	$ 35,000
2000	98,000
2001	40,000
2002	140,000
2003	70,000
Later Years	802,192
Total Principal Amount	1,185,192
Unamortized Discount	(9,403)
Total	$1,175,789

Short-term debt borrowings are limited by provisions of the 1935 Act to $300 million. Lines of credit are shared with AEP System companies and at December 31, 1998 and 1997 were available in the amounts of $763 million and $442 million, respectively. Facility fees of approximately 1/10 of 1% of the short-term lines of credit are required by the banks to maintain the lines of credit.

Outstanding short-term debt consisted of:

	Balance Outstanding (in thousands)	Year-end Weighted Average Interest Rate
December 31, 1998:		
Commercial Paper	$108,700	6.2%
December 31, 1997:		
Notes Payable	$ 56,410	6.3%
Commercial Paper	63,190	6.8
Total	$119,600	6.6

15. LEASES:

Leases of property, plant and equipment are for periods of up to 35 years and require payments of related property taxes, maintenance and operating costs. The Company is leasing 50% of the 1,300 mw Rockport 2 generating unit under an operating lease. The lease has 24 years remaining and total minimum lease payments of $1.8 billion. The majority of the leases have purchase or renewal options and will be renewed or replaced by other leases.

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

	Year Ended December 31, 1998	1997	1996
	(in thousands)		
Lease Payments on Operating Leases	$ 88,297	$ 92,067	$ 96,096
Amortization of Capital Leases	10,717	42,882	55,789
Interest on Capital Leases	10,302	9,737	10,624
Total Lease Rental Costs	$109,316	$144,686	$162,509

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

	December 31, 1998	December 31, 1997
	(in thousands)	
Electric Utility Plant Under Capital Leases:		
Production Plant	$ 8,850	$ 9,218
Distribution Plant	14,645	14,660
General Plant:		
Nuclear Fuel (net of amortization)	103,939	103,939
Other Plant	60,002	61,268
Total Electric Utility Plant Under Capital Leases	187,436	189,085
Accumulated Amortization	33,948	31,358
Net Electric Utility Plant Under Capital Leases	153,488	157,727
Other Property Under Capital Leases	37,672	40,746
Accumulated Amortization	4,733	3,246
Net Other Property Under Capital Leases	32,939	37,500
Net Properties Under Capital Leases	$186,427	$195,227
Capital Lease Obligations*:		
Noncurrent Liability	$176,760	$161,194
Liability Due Within One Year	9,667	34,033
Total Capital Lease Obligations	$186,427	$195,227

* Represents the present value of future minimum lease payments.

The noncurrent portion of capital lease obligations is included in other noncurrent liabilities in the Consolidated Balance Sheets. Properties under operating leases and related obligations are not included in the Consolidated Balance Sheets.

Future minimum lease payments consisted of the following at December 31, 1998:

	Capital Leases	Non-Cancelable Operating Leases
	(in thousands)	
1999	$ 15,807	$ 98,992
2000	14,371	98,729
2001	12,524	97,494
2002	18,521	95,778
2003	9,141	95,685
Later Years	38,505	1,608,787
Total Future Minimum Lease Payments	108,869(a)	$2,095,465
Less Estimated Interest Element	26,381	
Estimated Present Value of Future Minimum Lease Payments	82,488	
Unamortized Nuclear Fuel	103,939	
Total	$186,427	

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

16. UNAUDITED QUARTERLY FINANCIAL INFORMATION:

Quarterly Periods Ended	Operating Revenues	Operating Income	Net Income (Loss)
	(in thousands)		
1998			
March 31	$328,468	$51,368	$33,744
June 30	348,271	42,194	28,536
September 30	412,908	58,639	38,691
December 31	316,147	13,806	(4,343)
1997			
March 31	341,313	59,894	44,259
June 30	320,508	50,140	33,908
September 30	347,668	60,449	45,091
December 31	329,743	37,305	23,482

Fourth quarter 1998 operating income and net income declined primarily as a result of expenditures to prepare the nuclear units for restart.

See "Reclassification" in Note 1 regarding reclassification of prior period amounts.

OPERATING STATISTICS

	1998	1997	1996	1995	1994
OPERATING REVENUES (in thousands):					
Retail:					
Residential:					
Without Electric Heating	$ 265,442	$ 237,475	$ 232,212	$ 239,266	$ 227,358
With Electric Heating	108,950	110,547	111,556	109,504	107,523
Total Residential	374,392	348,022	343,768	348,770	334,881
Commercial	290,149	264,031	253,750	256,319	247,938
Industrial	370,329	332,218	312,777	298,256	291,527
Miscellaneous	6,849	6,465	6,445	6,482	6,316
Total Retail	1,041,719	950,736	916,740	909,827	880,662
Wholesale (sales for resale)	321,771	362,392**	391,478	357,441	352,889
Total Revenues from Energy Sales	1,363,490	1,313,128**	1,308,218	1,267,268	1,233,551
Other	42,304	26,104	20,275	15,889	17,758
Total Operating Revenues	$1,405,794	$1,339,232**	$1,328,493	$1,283,157	$1,251,309
SOURCES AND USES OF ENERGY (in millions of kilowatthours):					
Sources:					
Net Generated:					
Fossil Fuel	13,432	14,193	13,304	12,850	13,022
Nuclear Fuel	- *	10,421	16,396	13,999	9,291
Hydroelectric	116	133	99	86	95
Total Net Generated	13,548	24,747	29,799	26,935	22,408
Purchased and AEP Power Pool	13,621	9,557**	7,581	5,871	5,757
Total Sources	27,169	34,304**	37,380	32,806	28,165
Less: Losses, Company Use, Etc.	1,884	1,850	1,795	1,700	1,398
Net Sources	25,285	32,454**	35,585	31,106	26,767
Uses:					
Retail Sales:					
Residential:					
Without Electric Heating	3,518	3,307	3,329	3,390	3,210
With Electric Heating	1,616	1,768	1,811	1,768	1,727
Total Residential	5,134	5,075	5,140	5,158	4,937
Commercial	4,540	4,349	4,328	4,300	4,148
Industrial	7,755	7,541	7,295	6,582	6,453
Miscellaneous	86	82	82	82	82
Total Retail	17,515	17,047	16,845	16,122	15,620
Wholesale Sales (sales for resale)	7,770	15,407**	18,740	14,984	11,147
Total Uses	25,285	32,454**	35,585	31,106	26,767

* During 1998 the Company's nuclear plant was shutdown for an extended outage which began in September 1997 to address certain safety concerns. See Note 3.

**Reclassified

OPERATING STATISTICS (Concluded)

	1998	1997	1996	1995	1994
AVERAGE COST OF FUEL CONSUMED (in cents):					
Per Million Btu:	130	89	74	78	85
Per Kilowatthour Generated:	1.21	.93	.80	.83	.90
RESIDENTIAL SERVICE - AVERAGES:					
Annual Kwh Use per Customer:					
With Electric Heating	15,922	17,583	18,206	18,044	17,907
Total	10,566	10,560	10,791	10,943	10,572
Annual Electric Bill:					
With Electric Heating	$1,073.77	$1,099.34	$1,121.41	$1,117.55	$1,115.19
Total	$770.50	$724.16	$721.76	$739.99	$717.17
Price per Kwh (in cents):					
With Electric Heating	6.74	6.25	6.16	6.19	6.23
Total	7.29	6.86	6.69	6.76	6.78
NUMBER OF CUSTOMERS:					
Year-End:					
Retail:					
Residential:					
Without Electric Heating	386,253	383,314	378,757	375,929	372,473
With Electric Heating	102,078	101,492	100,372	99,105	97,402
Total Residential	488,331	484,806	479,129	475,034	469,875
Commercial	58,720	57,311	55,869	55,077	53,927
Industrial	5,437	5,484	5,345	5,316	5,213
Miscellaneous	1,956	1,855	1,820	1,797	1,806
Total Retail	554,444	549,456	542,163	537,224	530,821
Wholesale (sales for resale)	152	122	85	62	54
Total Electric Customers	554,596	549,578	542,248	537,286	530,875

DIVIDENDS AND PRICE RANGES OF CUMULATIVE PREFERRED STOCK
By Quarters (1998 and 1997)

	1998 - Quarters				1997 - Quarters			
	1st	2nd	3rd	4th	1st	2nd	3rd	4th
CUMULATIVE PREFERRED STOCK								
($100 Par Value)								
4-1/8% Series								
Dividends Paid Per Share	$1.03125	$1.03125	$1.03125	$1.03125	$1.03125	$1.03125	$1.03125	$1.03125
Market Price - $ Per Share								
(CSE) - High	-	-	-	-	-	-	-	-
- Low	-	-	-	-	-	-	-	-
4.56% Series								
Dividends Paid Per Share	$1.14	$1.14	$1.14	$1.14	$1.14	$1.14	$1.14	$1.14
Market Price - $ Per Share								
(OTC)								
Ask - High	-	-	-	-	-	-	-	-
- Low	-	-	-	-	-	-	-	-
Bid - High	58-1/2	66	67-5/8	68	52	52	57-5/8	58-1/4
- Low	58-1/4	58-1/2	66	64	52	52	52	57-5/8
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	59-3/8	63-7/8	64-5/8	67-3/8	63-1/8	58	58-1/4	58-1/4
- Low	58-1/4	59-3/8	63-7/8	64-5/8	50	58	58	58-1/4
5.90% Series								
Dividends Paid Per Share	$1.475	$1.475	$1.475	$1.475	$1.475	$1.475	$1.475	$1.475
Market Price - $ Per Share								
(OTC)								
Ask (high/low)	-	-	-	-	-	-	-	-
Bid (high/low)	-	-	-	-	-	-	-	-
6-1/4% Series								
Dividends Paid Per Share	$1.5625	$1.5625	$1.5625	$1.5625	$1.5625	$1.5625	$1.5625	$1.5625
Market Price - $ Per Share								
(OTC)								
Ask (high/low)	-	-	-	-	-	-	-	-
Bid (high/low)	-	-	-	-	-	-	-	-
6.30% Series								
Dividends Paid Per Share	$1.575	$1.575	$1.575	$1.575	$1.575	$1.575	$1.575	$1.575
Market Price - $ Per Share								
(OTC)								
Ask (high/low)	-	-	-	-	-	-	-	-
Bid (high/low)	-	-	-	-	-	-	-	-
6-7/8% Series								
Dividends Paid Per Share	$1.71875	$1.71875	$1.71875	$1.71875	$1.71875	$1.71875	$1.71875	$1.71875
Market Price - $ Per Share								
(OTC)								
Ask (high/low)	-	-	-	-	-	-	-	-
Bid (high/low)	-	-	-	-	-	-	-	-

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

INVESTOR INQUIRIES

Investors should direct inquiries to Investor Services using the toll free number, 1-800-AEP-COMP (1-800-237-2667) or by writing to:

Investor Services
American Electric Power Service Corporation
28th Floor
1 Riverside Plaza
Columbus, OH 43215-2373

FORM 10-K ANNUAL REPORT

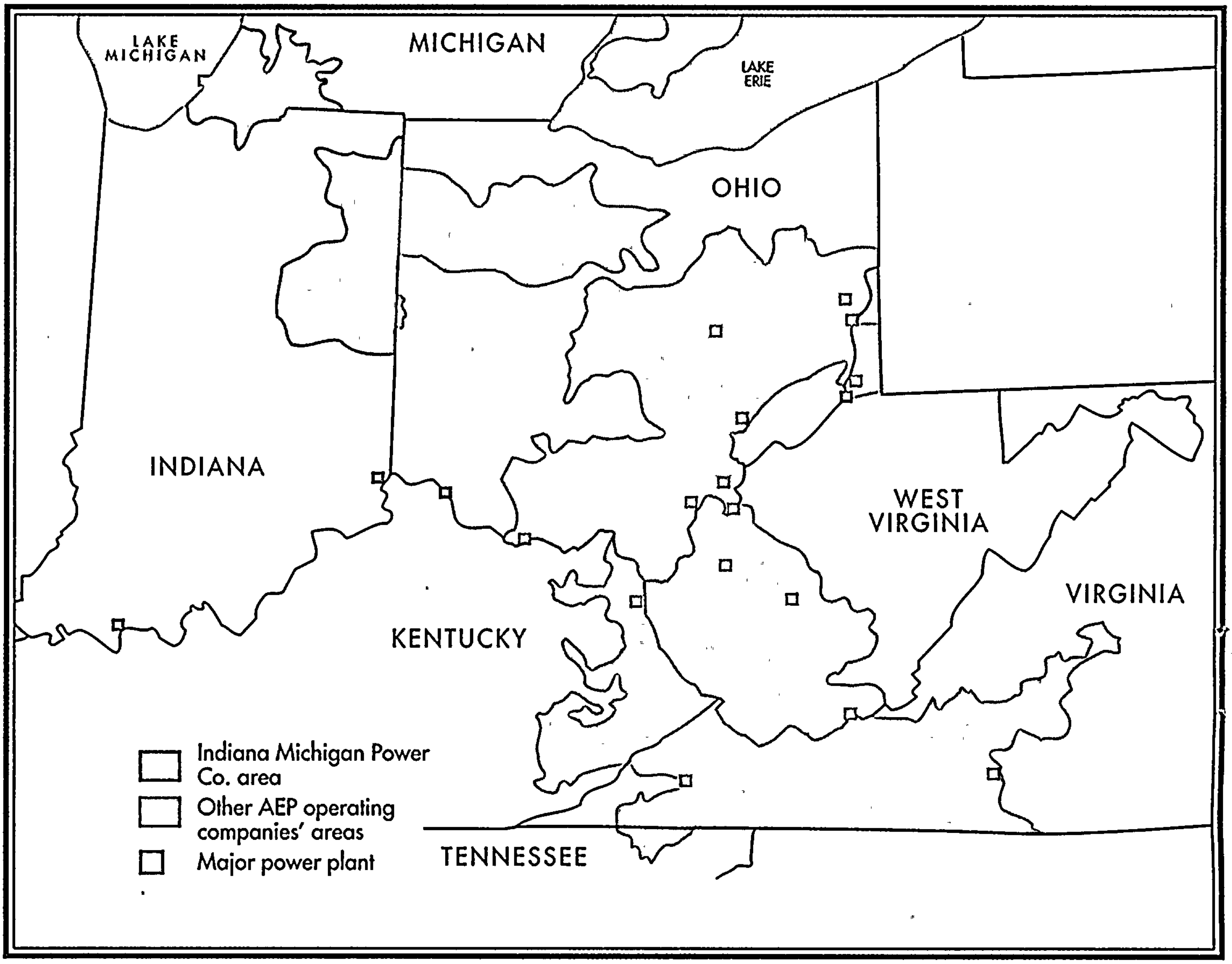
The Annual Report (Form 10-K) to the Securities and Exchange Commission will be available in April 1999 at no cost to shareholders. Please address requests for copies to:

Financial Reporting Division
American Electric Power Service Corporation
26th Floor
1 Riverside Plaza
Columbus, OH 43215-2373

TRANSFER AGENT AND REGISTRAR OF CUMULATIVE PREFERRED STOCK

First Chicago Division, Equiserve
P.O. Box 2500
Jersey City, NJ 07303-2500
Phone number: 1-800-328-6955

Indiana Michigan Power Service Area and the American Electric Power System



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ATTACHMENT 2 TO AEP:NRC:09090

INDIANA MICHIGAN POWER COMPANY'S
PROJECTED CASH FLOW FOR 1999

Indiana Michigan Power Co.
1999 Forecasted Internal Cash Flow
$Millions

	Projected 1999
Net Income After Taxes	99.5
Less: Dividends	114.4
	(14.9)
Adjustments:	
Depreciation and Amortization	148.5
Deferred Operating Costs	(86.2)
Deferred Federal Income Taxes and Investment Tax Credits	4.6
AFUDC	(9.2)
Other	(5.7)
Total Adjustments	52.0
Internal Cash Flow	37.1
Average Quarterly Cash Flow	9.3
Average Cash Balances and Short-Term Investments	2.9
Total	12.2