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RECEIVED

APR 03 2012

PUBLIC SERVICE
COMMISSION

Via Overnight Mail

April 2, 2012

Mr. Jeff Derouen, Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40602

Re: Case No. 2011-00401

Dear Mr. Derouen:

Please find enclosed the original and twelve (12) copies each of the RESPONSES OF KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC. to: 1) COMMISSION STAFF FIRST SET OF DATA REQUESTS (PUBLIC VERSION); and 2) KENTUCKY POWER COMPANY'S DATA REQUESTS dated MARCH 23, 2012 for filing in the above-referenced matter. Due to the size of the attachments in response to Kentucky Power's Data Request Nos. 1 and 2, we only include one paper copy, and the original and twelve (12) CD's containing same. I also enclose a copy of the CONFIDENTIAL pages to be filed under seal.

By copy of this letter, all parties listed on the Certificate of Service have been served. Please place this document of file.

Very Truly Yours,

Mike Kurtz

Michael L. Kurtz, Esq.
Kurt J. Boehm, Esq.
BOEHM, KURTZ & LOWRY

MLKkew
Attachment
cc: Certificate of Service

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing was served by mailing a true and correct copy via electronic mail (when available) and Overnight Mail, to all parties on this 2nd day of April, 2012.

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Kurt J. Boehm, Esq.

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Shannon Fisk
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Stites & Harbison
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Frankfort, KENTUCKY 40602-0634

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF: THE APPLICATION OF KENTUCKY POWER COMPANY FOR APPROVAL OF ITS 2011 ENVIRONMENTAL COMPLIANCE PLAN, FOR APPROVAL OF ITS AMENDED ENVIRONMENTAL COST RECOVERY SURCHARGE TARIFF, AND FOR THE GRANT OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION AND ACQUISITION OF RELATED FACILITIES	:	**Case No. 2011-00401**

RESPONSES OF
KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.
TO KENTUCKY POWER COMPANY'S DATA REQUESTS
DATED MARCH 23, 2012

1. Please provide in their original form, with all calculations operable and formulas intact and unprotected, all electronic spreadsheets and other calculations used, developed in connection with the preparation of, referenced, or contained in Mr. Hill's testimony, analyses, and exhibits filed in this proceeding.

RESPONSE: Please see the attached CD, which contains all of Mr. Hill's workpapers.

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APR 03 2012
PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF: THE APPLICATION OF KENTUCKY POWER COMPANY FOR APPROVAL OF ITS 2011 ENVIRONMENTAL COMPLIANCE PLAN, FOR APPROVAL OF ITS AMENDED ENVIRONMENTAL COST RECOVERY SURCHARGE TARIFF, AND FOR THE GRANT OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION AND ACQUISITION OF RELATED FACILITIES	:	**Case No. 2011-00401**

RESPONSES OF
KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.
TO KENTUCKY POWER COMPANY'S DATA REQUESTS
DATED MARCH 23, 2012

2. Please provide copies of all documents, articles, studies, or other publications referenced in Mr. Hill's testimony.

RESPONSE: Please see the attached CD, which contains all of Mr. Hill's workpapers.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF: THE APPLICATION OF KENTUCKY POWER COMPANY FOR APPROVAL OF ITS 2011 ENVIRONMENTAL COMPLIANCE PLAN, FOR APPROVAL OF ITS AMENDED ENVIRONMENTAL COST RECOVERY SURCHARGE TARIFF, AND FOR THE GRANT OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION AND ACQUISITION OF RELATED FACILITIES	:	**Case No. 2011-00401**

RESPONSES OF
KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.
TO KENTUCKY POWER COMPANY'S DATA REQUESTS
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3. Does Mr. Hill agree that bond rating agencies, such as Standard & Poor's Corporation, consider the impact of regulation on a utility's risks when evaluating credit ratings? If the answer is anything other than an unqualified, "yes", please provide a complete explanation.

RESPONSE: Yes, however we are not attempting to determine a bond rating for KPC in this proceeding, we are attempting to determine an allowed return on equity that is appropriate given the reduced risks afforded the companies by Kentucky's environmental surcharge regulation. The environmental surcharge mechanism is a much lower-risk regulatory mechanism than is normal rate-base-rate-of-return regulation. That is because, as set out in Section 278.138 of the Kentucky Code the Company is able to recover all of its costs of complying with environmental requirements (capital costs, operating expenses, equipment, property, taxes, overheads, depreciation) "in the second month following the month in which costs are incurred." While those costs are, of course, subject to periodic review by the Commission for accuracy, that mechanism represents a very

COMMONWEALTH OF KENTUCKY
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IN THE MATTER OF: THE APPLICATION OF KENTUCKY POWER COMPANY FOR APPROVAL OF ITS 2011 ENVIRONMENTAL COMPLIANCE PLAN, FOR APPROVAL OF ITS AMENDED ENVIRONMENTAL COST RECOVERY SURCHARGE TARIFF, AND FOR THE GRANT OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION AND ACQUISITION OF RELATED FACILITIES	:	**Case No. 2011-00401**

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reliable and timely recovery of all costs of operation. Also those costs are not subject to re-setting through a "rate case" type of structure, the costs are what they are and the Company is entitled to recover them—including the allowed rate of return. With a normal rate proceeding, the utility's overall costs are included in the rates they are allowed to charge. If sales or costs differ from expectations, the return earned by the Company and its investors can vary—and the point here is that the variance of the return earned in a normal rate base proceeding, which does not allow on-going, very rapid recovery of actual costs, would be far greater than those earned in an environmental surcharge proceeding such as this. A higher return volatility indicates a higher required return and vice versa.

COMMONWEALTH OF KENTUCKY
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RESPONSES OF
KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.
TO KENTUCKY POWER COMPANY'S DATA REQUESTS
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4. Please refer to page 3, line 18 through page 4, line 9, of Mr. Hill's testimony. Please provide a list of all cost recovery mechanisms applicable to each of the utilities in Mr. Hill's proxy group, including all environmental cost recovery trackers. If Mr. Hill did not examine the extent to which his proxy utilities operate under similar adjustment mechanisms, please explain why not, including any support for his decision not to do so.

RESPONSE: Mr. Hill has not conducted such a study because such data are not readily available, making any such study time-consuming, unnecessarily expensive and, therefore, outside the budget allotted for this proceeding. Rather, Mr. Hill is relying on his 30-year experience in utility regulation to conclude that a regulatory cost-recovery mechanism that allows a utility to recover environmental-related capital costs from ratepayers within two months of the expenditure of those costs is uncommon and indicates that the Companies' environmental plant investments have lower investment risk than that afforded traditional utility plant investment. Therefore, those investments deserve a lower rate of return.

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RESPONSES OF
KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.
TO KENTUCKY POWER COMPANY'S DATA REQUESTS
DATED MARCH 23, 2012

5. Please refer to page 4, lines 5-6, of Mr. Kollen's testimony. Please provide all supporting calculations and spreadsheets -with all calculations operational and formulas intact and unprotected-that were utilized to determine or otherwise relied upon by Mr. Kollen to support his testimony that "the purchase option" would yield a rate increase impact in 2016 of between "9.9% to 11.9%."

RESPONSE

Please see attached excel file entitled "Rate Increase Effects from PJM Purchases Option." Data sources are identified on the tables shown on page 14, line 1 and page 15, line 2 in Mr. Kollen's Direct Testimony and on Exhibit___(LK-3).

Kentucky Power Company
Rate Increase Effects from Utilizing 10-Year PJM Purchases Option
First Year Savings - 2016
($ Millions)

All Savings Quantified for First Year - 2016	PJM Savings Low Range	PJM Savings Low Range
Estimated Savings by Utilizing Ten Year PJM Purchase Option - Total Co.	104	117
Additional Savings Estimated by Kollen	36	36
Total Estimated Savings	140	153
KY Jurisdictional Factor	94.61%	94.61%
Estimated Savings by Utilizing Ten Year PJM Purchase Option - KY Retail	133	144
KY Jurisdiction 12-month Revenue	570	570
Percentage Rate Increase Savings	23.30%	25.36%
Percentage Increase - Total KY Retail Under Company's Proposal	35.23%	35.23%
Percentage Rate Increase	11.93%	9.87%

Note: Testimony Includes These Ten Year Savings Balances on Pages 13-15

Estimated Savings by Utilizing Ten Year PJM Purchase Option - Total Co.	431	742
Additional Savings Estimated by Kollen	43	43
Total Estimated Savings	474	785

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RESPONSES OF
KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.
TO KENTUCKY POWER COMPANY'S DATA REQUESTS
DATED MARCH 23, 2012

6. Please refer to Mr. Kollen's testimony at page 8, lines 3-9. Provide all supporting spreadsheets - with all calculations operational and formulae intact and unprotected-that were used to determine the $9.326 million increase in revenue requirement referred to by Mr. Kollen his testimony.

RESPONSE

Please see attached excel file entitled "Exhibit___(LK-24)."

Kentucky Power Company
Current ECR Revenue Requirement Comparison
Based on November 2011 ECR Filing
KIUC Adjustment to Reduce ROE to 9.2%

Big Sandy ECR Rate Base - Total Company ES Form 3.10	90,394,789
Kentucky Retail Jurisdictional Allocation Factor - ES Form 1.00	83.3%
Big Sandy ECR Rate Base - Kentucky Retail	75,298,859

Annual Revenue Requirement Reduction from Reducing ROE to 9.2%	(677,690)

Big Sandy - Rate of Return - ES Form 3.15

Current Rate of Return	Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost
Long Term Debt	51.941%	6.48%	3.37%	3.37%
A/R Financing	4.116%	1.22%	0.05%	0.05%
Common Equity	43.943%	10.50%	4.61%	7.27%
Total Capital	100.00%		8.03%	10.69%

Combined Tax Rate = 36.555%

Rate of Return - Adjusted to Reflect ROE of 9.2%	Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost
Long Term Debt	51.941%	6.48%	3.37%	3.37%
A/R Financing	4.116%	1.22%	0.05%	0.05%
Common Equity	43.943%	9.20%	4.04%	6.37%
Total Capital	100.00%		7.46%	9.79%

Kentucky Power Company
Initial Revenue Requirements Comparison
With As Filed ROE of 10.5% Compared to KIUC Adjusted ROE of 9.2%
Based on Revised Revenue Requirement - Response to Staff 1-20

	As Revised Beginning of Year 1	As Revised Adjusted for 9.2% ROE Year 1	Reduction In Initial Revenue Requirement
Eligible Plant - Placed In Service	955,512,492	955,512,492	
Less: Accumulated Depreciation			
Less: Deferred Tax Balance			
In-Service Rate Base	955,512,492	955,512,492	
Grossed Up Rate of Return	10.69%	9.79%	
Return on Revenue Requirement - Total Company	102,144,285	93,544,673	
Annual KY Jurisdiction Revenue Allocation Factor	78.91%	78.91%	
Return On Revenue Requirement - KY Jurisdiction	80,602,056	73,816,101	(6,785,954)
Revenue Requirement - Operating Expenses - KY Jurisdiction	89,750,145	89,750,145	-
Total KY Retail Revenue Requirement	170,352,201	163,566,247	(6,785,954)
KY Jurisdiction 12-month Revenue	569,593,245	569,593,245	569,593,245
Percentage Rate Increase	29.91%	28.72%	-1.19%

Kentucky Power Company
Revenue Requirements Comparison
As Filed vs. KIUC Recommended ROE of 9.2%
Grossed Up Rate of Return

Rate of Return - As Filed	Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost
Long Term Debt	51.941%	6.48%	3.37%	3.37%
A/R Financing	4.116%	1.22%	0.05%	0.05%
Common Equity	43.943%	10.50%	4.61%	7.27%
Total Capital	100.000%		8.03%	10.69%

Combined Tax Rate = 36.555%

Rate of Return - Adjusted to Reflect ROE of 9.2%	Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost
Long Term Debt	51.941%	6.48%	3.37%	3.37%
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COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF: THE APPLICATION OF KENTUCKY POWER COMPANY FOR APPROVAL OF ITS 2011 ENVIRONMENTAL COMPLIANCE PLAN, FOR APPROVAL OF ITS AMENDED ENVIRONMENTAL COST RECOVERY SURCHARGE TARIFF, AND FOR THE GRANT OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION AND ACQUISITION OF RELATED FACILITIES	:	**Case No. 2011-00401**

RESPONSES OF
KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.
TO KENTUCKY POWER COMPANY'S DATA REQUESTS
DATED MARCH 23, 2012

7. Please refer to Mr. Kollen's testimony at page 9, lines 2-7. Provide all calculations in electronic spreadsheet format, with all calculations operable and formulas intact and unprotected, that support or were relied upon by Mr. Kollen in calculating the 35.23% "total percentage increase to retail customers" to which Mr. Kollen testifies.

RESPONSE

Please see attached excel file entitled "Exhibit___(LK-3)."

Kentucky Power Company
Kentucky Jurisdiction Total Retail Effect from Big Sandy 2 Retrofit Costs
($ millions)

Total Company First Year Revenue Requirement - Revised in Staff 1-20		206.556
Add: Total Company Revenue Requirement Related to SO2 and NOX Consumption		5.562
Total Company First Year Revenue Requirement - Corrected		212.118
Revenue Requirement Associated with Off System Sales at 10.88%	23.078	
Percentage Retained by KPC through System Sales Clause in its FAC	40%	
(Company Share 40% - Customer Share 60%)		
Maximum Amount Retained by KPC through System Sales Clause in its FAC		(9.231)
Total Company Total Revenue Requirement Less Amount Retained by KPCO		202.886
KY Jurisdictional Revenue Allocation Factor		98.91%
KY Jursidiction Total Retail Revenue Requirement Effect of Big Sandy 2 Retrofit		200.675
KY Jurisdiction Revenues from Exhibit LPM-13		569.593
Retail Increase for BS2 Retrofit Projects		35.23%

Sources: Revised Revenue Requirement Schedules in Response to Staff 1-20
Response to KIUC 2-18
Exhibit LPM-5 - 12 Month Avg OSS = 10.88%
KPC Tariff Sheet 19-1 and 19-2 and 2011 KPC FAC Filings

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF: THE APPLICATION OF KENTUCKY POWER COMPANY FOR APPROVAL OF ITS 2011 ENVIRONMENTAL COMPLIANCE PLAN, FOR APPROVAL OF ITS AMENDED ENVIRONMENTAL COST RECOVERY SURCHARGE TARIFF, AND FOR THE GRANT OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION AND ACQUISITION OF RELATED FACILITIES	:	**Case No. 2011-00401**

RESPONSES OF
KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.
TO KENTUCKY POWER COMPANY'S DATA REQUESTS
DATED MARCH 23, 2012

8. Please refer to Mr. Kollen's Exhibit LK-3.

   a. Please provide Exhibit LK-3 in electronic spreadsheet format, with all calculations operable and formulas intact and unprotected;

   b. Please provide a complete explanation, including all support, of the basis for Mr. Kollen's allocation of all of the costs of the DHGD only to the retail and wholesale customers, with none being allocated to the non-associated or the associated utility sales.

RESPONSE:

a. Please see attached excel file entitled "Exhibit___(LK-3)."

b. Please refer to Mr. Kollen's Direct Testimony at page 8, line 11 through page 9 line 7. Mr. Kollen explains that the retail ratepayers ultimately are responsible for the entirety of the costs of the DHGD, except for a small portion that is retained by the Company through the SSC and another small portion that is allocated to all-requirements wholesale customers. In recognition of this fact, on Exhibit__(LK-3), Mr. Kollen starts with the total Company revenue requirement for the DHGD, then subtracts the portion retained by the Company through the SSC and then allocates the residual to the retail jurisdiction.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

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RESPONSES OF
KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.
TO KENTUCKY POWER COMPANY'S DATA REQUESTS
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9. Please refer to page 31, lines 11-30 of Mr. Kollen's testimony and Exhibit LK-15. Please provide Exhibit LK-15 in electronic spreadsheet format, with all calculations operable and formulas intact and unprotected.

RESPONSE

Please see attached excel file entitled "Exhibit___(LK-15)."

Kentucky Power Company
Revenue Requirement During Construction Period
For Big Sandy 2 Retrofit
Based on Using 100% CWIP in Rate Base

	As Filed Rate of Return	50% Short Term Debt	100% Short Term Debt
Construction Year 1	2,084,550	1,146,600	48,750
Construction Year 2	9,888,250	5,439,000	231,250
Construction Year 3	25,174,950	13,847,400	588,750
Construction Year 4	48,692,950	26,783,400	1,138,750
Construction Year 4 and 5/12	31,735,938	17,456,250	742,188
Total Revenue Requirement	117,576,638	64,672,650	2,749,688

Construction Adds By Year	Beg Year CWIP ($)	Direct Adds ($)	End Year CWIP ($)	Avg CWIP in RB
Const YR 1		39,000,000	39,000,000	19,500,000
Const YR 2	39,000,000	107,000,000	146,000,000	92,500,000
Const YR 3	146,000,000	179,000,000	325,000,000	235,500,000
Const YR 4	325,000,000	261,000,000	586,000,000	455,500,000
Const YR 4.5	586,000,000	253,000,000	839,000,000	712,500,000
Total		839,000,000		

Kentucky Power Company
Revenue Requirement During Construction Period
For Big Sandy 2 Retrofit
Based on Using 100% CWIP in Rate Base

Rate of Return - As Filed Traditional Financing	Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost
Long Term Debt	51.94%	6.48%	3.37%	3.37%
A/R Financing	4.12%	1.22%	0.05%	0.05%
Common Equity	43.94%	10.50%	4.61%	7.27%
Total Capital	100.00%		8.03%	10.69%

Combined Tax Rate = 36.5555%

50% STD at 0.25%	Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost
Short Term Debt	50.00%	0.25%	0.13%	0.13%
Long Term Debt	25.00%	6.48%	1.62%	1.62%
Common Equity	25.00%	10.50%	2.63%	4.14%
Total Capital	100.00%		4.37%	5.88%

Combined Tax Rate = 36.5555%

100% STD at 0.25%	Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost
Short Term Debt	100.00%	0.25%	0.25%	0.25%
Long Term Debt	0.00%	0.00%	0.00%	0.00%
Common Equity	0.00%	0.00%	0.00%	0.00%
Total Capital	100.00%		0.25%	0.25%

Combined Tax Rate = 36.5555%

COMMONWEALTH OF KENTUCKY
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RESPONSES OF
KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.
TO KENTUCKY POWER COMPANY'S DATA REQUESTS
DATED MARCH 23, 2012

10. Please refer to the chart presented at the top of page 37 of Mr. Kollen's testimony. Please provide:

    a. the chart presented at top of page 37 of Mr. Kollen's testimony in electronic format;

    b. in electronic spreadsheet format, with all calculations operable and formulas intact and unprotected, all calculations used to construct the chart presented at top of page 37 of Mr. Kollen's testimony;

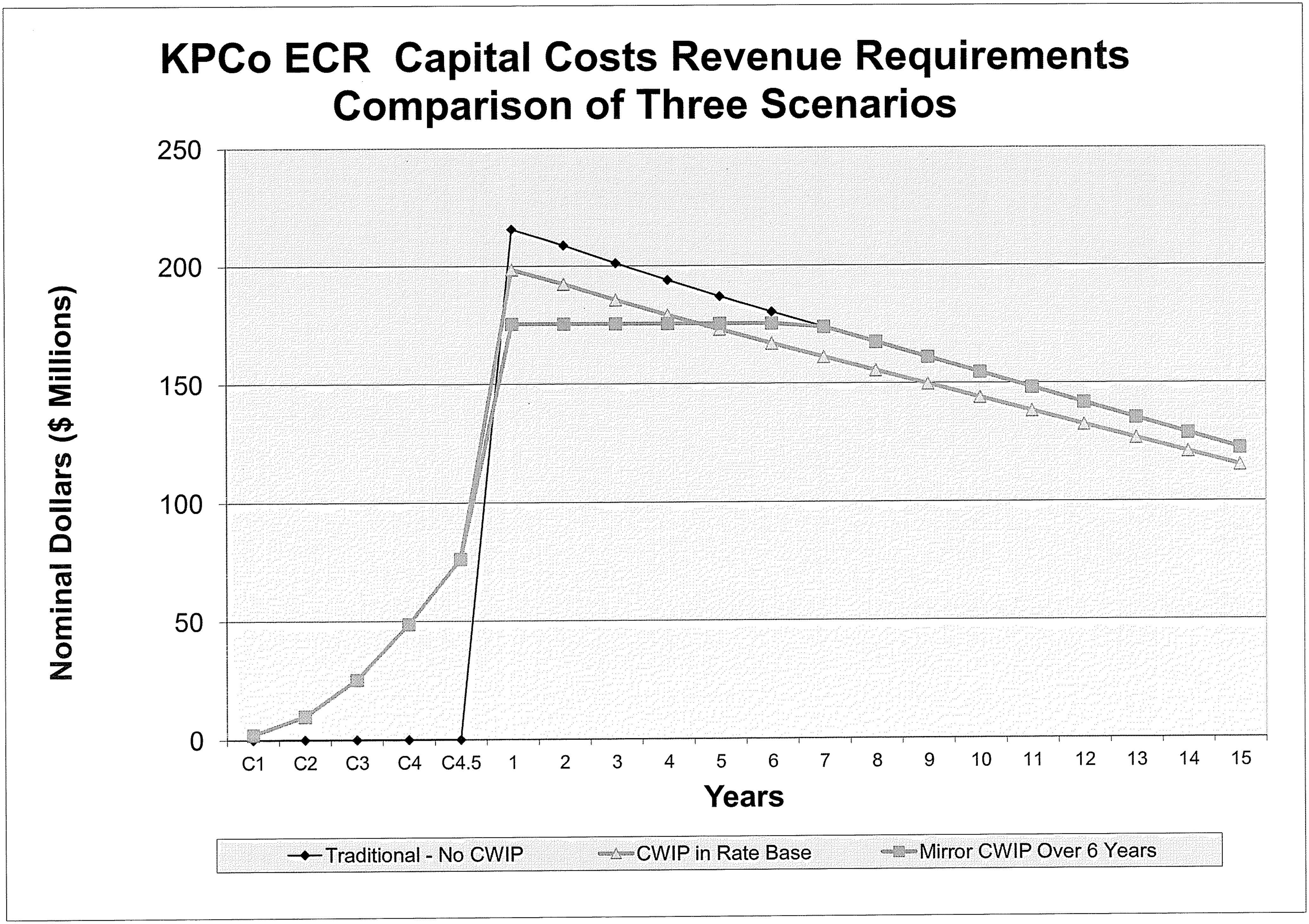
    c. the source of all data used in the calculations referred to in subpart (b) of this data request.

RESPONSE

a. Please see attached excel file entitled "KPCo Mirror CWIP Charts."

b. Refer to the response subpart (a) of this question.

c. The data sources are identified in the attached file.


KPCo ECR Capital Costs Revenue Requirements
Comparison of Three Scenarios
Nominal Dollars ($ Millions)
250
200
150
100
50
0
C1
C2
C3
C4
C4.5
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
Years
Traditional - No CWIP
CWIP in Rate Base
Mirror CWIP Over 6 Years

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

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RESPONSES OF
KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.
TO KENTUCKY POWER COMPANY'S DATA REQUESTS
DATED MARCH 23, 2012

11. Please refer to the chart presented at the top of page 40 of Mr. Kollen's testimony. Please provide:

    a. the chart presented at top of page 40 of Mr. Kollen's testimony in electronic format;

    b. in electronic spreadsheet format, with all calculations operable and formulas intact and unprotected, all calculations used to construct the chart presented at top of page 40 of Mr. Kollen's testimony.

    c. the source of all data used in the calculations referred to in subpart (b) of this data request.

RESPONSE

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c. The data sources are identified in the attached file.

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RESPONSES OF
KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.
TO KENTUCKY POWER COMPANY'S DATA REQUESTS
DATED MARCH 23, 2012

12. Please refer to Exhibit LK-24 of Mr. Kollen's testimony. Please provide:
    a. Exhibit LK-24 of Mr. Kollen's testimony in electronic spreadsheet format, with all calculations operable and formulas intact and unprotected;
    b. the source of all data used in the spreadsheet and calculations referred to in subpart (a) of this data request.

RESPONSE

a. Please see attached excel file entitled "Exhibit___(LK-24)."

b. Refer to the response subpart (a) of this question.

c. The data sources are identified in the attached file.

Kentucky Power Company
Current ECR Revenue Requirement Comparison
Based on November 2011 ECR Filing
KIUC Adjustment to Reduce ROE to 9.2%

Big Sandy ECR Rate Base - Total Company ES Form 3.10	90,394,789
Kentucky Retail Jurisdictional Allocation Factor - ES Form 1.00	83.3%
Big Sandy ECR Rate Base - Kentucky Retail	75,298,859
Annual Revenue Requirement Reduction from Reducing ROE to 9.2%	(677,690)

Big Sandy - Rate of Return - ES Form 3.15

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A/R Financing	4.116%	1.22%	0.05%	0.05%
Common Equity	43.943%	10.50%	4.61%	7.27%
Total Capital	100.00%		8.03%	10.69%

Combined Tax Rate = 36.555%

Rate of Return - Adjusted to Reflect ROE of 9.2%	Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost
Long Term Debt	51.941%	6.48%	3.37%	3.37%
A/R Financing	4.116%	1.22%	0.05%	0.05%
Common Equity	43.943%	9.20%	4.04%	6.37%
Total Capital	100.00%		7.46%	9.79%

Kentucky Power Company
Initial Revenue Requirements Comparison
With As Filed ROE of 10.5% Compared to KIUC Adjusted ROE of 9.2%
Based on Revised Revenue Requirement - Response to Staff 1-20

	As Revised Beginning of Year 1	As Revised Adjusted for 9.2% ROE Year 1	Reduction In Initial Revenue Requirement
Eligible Plant - Placed In Service	955,512,492	955,512,492	
Less: Accumulated Depreciation			
Less: Deferred Tax Balance			
In-Service Rate Base	955,512,492	955,512,492	
Grossed Up Rate of Return	10.69%	9.79%	
Return on Revenue Requirement - Total Company	102,144,285	93,544,673	
Annual KY Jurisdiction Revenue Allocation Factor	78.91%	78.91%	
Return On Revenue Requirement - KY Jurisdiction	80,602,056	73,816,101	(6,785,954)
Revenue Requirement - Operating Expenses - KY Jurisdiction	89,750,145	89,750,145	-
Total KY Retail Revenue Requirement	170,352,201	163,566,247	(6,785,954)
KY Jurisdiction 12-month Revenue	569,593,245	569,593,245	569,593,245
Percentage Rate Increase	29.91%	28.72%	-1.19%

Kentucky Power Company
Revenue Requirements Comparison
As Filed vs. KIUC Recommended ROE of 9.2%
Grossed Up Rate of Return

Rate of Return - As Filed	Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost
Long Term Debt	51.941%	6.48%	3.37%	3.37%
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Total Capital	100.000%		7.46%	9.79%

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF: THE APPLICATION OF KENTUCKY POWER COMPANY FOR APPROVAL OF ITS 2011 ENVIRONMENTAL COMPLIANCE PLAN, FOR APPROVAL OF ITS AMENDED ENVIRONMENTAL COST RECOVERY SURCHARGE TARIFF, AND FOR THE GRANT OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION AND ACQUISITION OF RELATED FACILITIES	:	**Case No. 2011-00401**

RESPONSES OF
KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.
TO KENTUCKY POWER COMPANY'S DATA REQUESTS
DATED MARCH 23, 2012

Respectfully submitted,

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COUNSEL FOR KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

April 2, 2012

EDUCATION AND EMPLOYMENT HISTORY
STEPHEN G. HILL

EDUCATION

Auburn University - Auburn, Alabama - Bachelor of Science in Chemical Engineering (1971); Honors - member Tau Beta Pi national engineering honorary society, Dean's list, candidate for outstanding engineering graduate; Organizations - Engineering Council, American Institute of Chemical Engineers

Tulane University - New Orleans, Louisiana - Masters in Business Administration (1973); concentration: Finance; awarded scholarship; Organizations - member MBA curriculum committee, Vice-President of student body, academic affairs

Continuing Education - NARUC Regulatory Studies Program at Michigan State University

EMPLOYMENT

West Virginia Air Pollution Control Commission (1975)
Position: Engineer ; Responsibility: Overseeing the compliance of all chemical companies in the State with the pollution guidelines set forth in the Clean Air Act.

West Virginia Public Service Commission-Consumer Advocate (1982)
Position: Rate of Return Analyst ; Responsibility: All rate of return research and testimony promulgated by the Consumer Advocate; also, testimony on engineering issues, when necessary.

Hill Associates (1989)
Position: Principal; Responsibility: Expert testimony regarding financial and economic issue in regulated industries.

PUBLICATIONS

"The Market Risk Premium and the Proper Interpretation of Historical Data," Proceedings of the Fourth NARUC Biennial Regulatory Information Conference, Volume I, pp. 245-255.
"Use of the Discounted Cash Flow Has Not Been Invalidated," Public Utilities Fortnightly, March 31, 1988, pp. 35-38.
"Private Equity Buyouts of Public Utilities: Preparation for Regulators," National Regulatory Research Institute, Paper 07-11, December 2007.

MEMBERSHIPS

American Institute of Chemical Engineers; Society of Utility and Regulatory Financial Analysts (Certified Rate of Return Analyst, Member of the Board of Directors)

PRIOR EXPERIENCE

Mr. Hill, is a Certified Rate of Return Analyst, doing business as Hill Associates. He has testified in more than 270 regulatory proceedings over the past twenty eight years on cost of capital, financial, economic, and corporate governance issues related to regulated industries. He has provided testimony in electric, gas, telephone, and water utility rate proceedings as well as in proceedings related to utility diversification, deregulation, and financial policy. In those cases, he has testified on behalf of consumer advocates, attorneys general and utility commissions. In addition, he has testified on cost of capital issues in auto, homeowners and workers' compensation insurance rate proceedings. Mr. Hill has also been an advisor to the Arizona Corporation Commission on matters of utility finance in bankruptcy proceedings.

Mr. Hill has testified before the West Virginia Public Service Commission, the Connecticut Department of Public Utility Control, the Oklahoma State Corporation Commission, the Public Utilities Commission of the State of California, the Pennsylvania Public Utilities Commission, the Maryland Public Service Commission, the Public Utilities Commission of the State of Minnesota, the Ohio Public Utilities Commission, the Insurance Commissioner of the State of Texas, the North Carolina Insurance Commissioner, the Rhode Island Public Utilities Commission, the City Council of Austin, Texas, the Texas Railroad Commission, the Arizona Corporation Commission, the South Carolina Public Service Commission, the Public Utilities Commission of the State of Hawaii, the New Mexico Corporation Commission, the State of Washington Utilities and Transportation Commission, the Georgia Public Service Commission, the Public Service Commission of Utah, the Kentucky Public Utilities Commission, the Illinois Commerce Commission, the Kansas Corporation Commission, the Indiana Utility Regulatory Commission, the Virginia Corporation Commission, the Montana Public Service Commission, the Public Service Commission of the State of Maine, the Public Service Commission of Wisconsin, the Vermont Public Service Board, the Federal Communications Commission and the Federal Energy Regulatory Commission.

UTILITY GROWTH RATE FUNDAMENTALS

Q. PLEASE PROVIDE AN EXAMPLE THAT DESCRIBES THE DETERMINANTS OF LONG-TERM SUSTAINABLE GROWTH.

A. Assume that a hypothetical regulated firm had a first-period common equity or book value per share of $10, the investor-expected return on that equity was 10% and the stated company policy was to pay out 60% of earnings in dividends. The first period earnings per share are expected to be $1.00 ($10/share book equity x 10% equity return) and the expected dividend is $0.60. The amount of earnings not paid out to shareholders ($0.40)—the retained earnings—raises the book value of the equity to $10.40 in the second period. The table below continues the hypothetical for a five-year period and illustrates the underlying determinants of growth.

TABLE A.

	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	GROWTH
BOOK VALUE	$10.00	$10.40	$10.82	$11.25	$11.70	4.00%
EQUITY RETURN	10%	10%	10%	10%	10%	—
EARNINGS/SH.	$1.00	$1.040	$1.082	$1.125	$1.170	4.00%
PAYOUT RATIO	0.60	0.60	0.60	0.60	0.60	—
DIVIDENDS/SH.	$0.60	$0.624	$0.649	$0.675	$0.702	4.00%

We see that under steady-state conditions, the earnings, dividends, and book value all grow at the same rate. Moreover, the key to this growth is the amount of earnings retained or reinvested in the firm and the return on that new portion of equity. If we let "b" equal the retention ratio of the firm (1 – the payout ratio) and let "r" equal the firm's expected return on equity, the DCF growth rate "g" (also referred to as the internal or sustainable growth rate) is equal to their product, or

$$g = br. \qquad \text{(i)}$$

Professor Myron Gordon, who developed the Discounted Cash Flow technique and first introduced it into the regulatory arena, has determined that Equation (i) embodies the underlying fundamentals of growth and, therefore, is a primary measure of growth to be used in the DCF model. Professor Gordon's research also indicates that analysts' growth rate projections are useful in estimating investors' expected sustainable growth.

I should note here that the above hypothetical does not allow for the existence of external sources of equity financing, *i.e.*, sales of common stock. Stock financing will cause investors to expect additional growth if the company is expected to issue new shares at a market price that exceeds book value. The excess of market over book would inure to the benefit of current shareholders, increasing their per-share equity value. Therefore, if the company is expected to continue to issue stock at a price that exceeds book value, the shareholders would continue to expect their book value to increase and would add that growth expectation to that stemming from earnings retention or internal growth. Conversely, if a company were expected to issue new equity at a price below book value, that would have a negative effect on shareholder's current growth rate expectations. In such a situation, shareholders would perceive an overall growth rate less than that produced by internal sources (retained earnings). Finally, with little or no expected equity financing or a market-to-book ratio near unity, investors would expect the sustainable growth rate for the company to equal that derived from Equation (i), "g = br." Dr. Gordon identifies the growth rate, [1] which includes both expected internal and external financing, as:

$$g = br + sv, \qquad \text{(ii)}$$

where,

g = DCF expected growth rate,
r = return on equity,
b = retention ratio,
v = fraction of new common stock sold that accrues to the current shareholder,
s = funds raised from the sale of stock

[1]Gordon, M.J., The Cost of Capital to a Public Utility, MSU Public Utilities Studies, East Lansing, Michigan, 1974, pp., 30–33.

as a fraction of existing equity.

Additionally,

$$v = 1 - BV/MP, \qquad \text{(iii)}$$

where,

MP = market price,
BV = book value.

I have used Equation (iii) as the basis for my examination of the investor-expected long-term growth rate (g) in this proceeding.

Q. IN YOUR PREVIOUS EXAMPLE, EARNINGS AND DIVIDENDS GREW AT THE SAME RATE (br) AS DID BOOK VALUE. WOULD THE GROWTH RATE IN EARNINGS OR DIVIDENDS, THEREFORE, BE SUITABLE FOR DETERMINING THE DCF GROWTH RATE ?

A. No, not necessarily. Rates of growth derived from earnings or dividends alone can be unreliable due to extraneous influences on those parameters, such as changes in the expected rate of return on common equity or changes in the payout ratio. That is why it is necessary to examine the underlying determinants of growth through the use of a sustainable growth rate analysis.

If we take the hypothetical example previously stated and assume that, in year three, the expected return on equity rises to 15%, the resultant growth rate for earnings and dividends far exceeds that which the company could sustain indefinitely. The potential error in using those growth rates to estimate “g” is illustrated in the following table.

TABLE B.

	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	GROWTH
BOOK VALUE	$10.00	$10.40	$10.82	$11.47	$12.157	5.00%
EQUITY RETURN	10%	10%	15%	15%	15%	10.67%
EARNINGS/SH.	$1.00	$1.040	$1.623	$1.720	$1.824	16.20%
PAYOUT RATIO	0.60	0.60	0.60	0.60	0.60	—
DIVIDENDS/SH.	$0.60	$0.624	$0.974	$1.032	$1.094	16.20%

What has happened is a shift in steady-state growth paths. For years one and two, the sustainable rate of growth (g=br) is 4.0%, just as in the previous hypothetical. Then, in the last three years, the sustainable growth rate increases to 6.0% (g = br = 0.4 x 15%). If the regulated firm was expected to continue to earn a 15% return on equity and retain 40% of its earnings, then a growth rate of 6.0% would be a reasonable estimate of the long-term sustainable growth rate. However, the compound annual growth rate for dividends and earnings exceeds 16%, which is the result only of an increased equity return rather than the intrinsic ability of the firm to grow continuously at a 16% annual rate. Clearly, this type of estimate of future growth cannot be used with any reliability at all. In the case of the hypothetical, to utilize a 16% growth rate in a DCF model would be to expect the company's return on common equity to increase by 50% every five years into the indefinite future. This would be a ridiculous forecast for any regulated firm and underscores the importance of utilizing the underlying fundamentals of growth in the DCF model.

It can also be demonstrated that a change in our hypothetical regulated firm's payout ratio makes the past rate of growth in dividends an unreliable basis for predicting "g." If we assume our regulated firm consistently earns its expected equity return (10%) but in the third year changes its payout ratio from 60% to 80% of earnings, the results are shown in the table below.

TABLE C.

	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	GROWTH
BOOK VALUE	$10.00	$10.40	$10.82	$11.036	$11.26	3.01%
EQUITY RETURN	10%	10%	10%	10%	10%	-
EARNINGS/SH.	$1.00	$1.040	$1.082	$1.104	$1.126	3.01%
PAYOUT RATIO	0.60	0.60	0.80	0.80	0.80	7.46%
DIVIDENDS/SH.	$0.60	$0.624	$0.866	$0.833	$0.900	10.67%

What we see here is that, although the company has registered a high dividend growth rate (10.67%), it is, again, not at all representative of the growth that could be sustained indefinitely, as called for in the DCF model. In actuality, the sustainable growth rate has declined from 4.0% the first two years to only 2.0% (g = br = 0.2 x 10%) during the last three years due to the increased payout ratio. To utilize a 10% growth rate in a DCF analysis of this hypothetical regulated firm would 1) assume the payout ratio of the firm would continue to increase 33% every five years into the indefinite future, 2) lead to the highly implausible result that the firm intends to consistently pay out more in dividends than it earns, and 3) grossly overstate the cost of equity capital.

INDIVIDUAL SAMPLE COMPANY GROWTH RATE ANALYSES

ELECTRIC UTILITIES

FE – First Energy - FE's sustainable growth rate has averaged 6.10% over the most recent five-year period (2006-2010). In the most recent year, the company's sustainable growth was below that five-year average indicating a declining trend. Value Line (VL) expects FE's sustainable growth to continue near that more recent growth rate level and reach approximately 3.9% by the 2014-2016 period. However, countering the lower growth indication, FE's book value growth rate is expected to be 5.0% over the next five years, higher than the historical growth of 1.0%, and above sustainable growth projections. FE's earnings per share are projected to increase at a 0.5% (VL) rate, while Zacks and IBES publish growth rate expectations for this company of 1% and 1.85%, respectively. Over the past five years, FE's earnings growth was 9.0% but its dividends increased at a 5% rate, according to Value Line. Also, dividends are expected to grow at a 0.5% rate over the next three to five-year period, moderating long-term growth expectations. Investors can reasonably expect long-term sustainable growth rate in the future to be lower than the past; a growth rate of **4.0%** is reasonable for FE.

Regarding share growth, FE's shares outstanding increased at a negative 1.14% rate over the past five years. A large number of shares was issued in the acquisition of Allegheny Energy in 2011. Following that increase in the number of shares outstanding (which would not be expected to be continuing in nature), FE's shares are not expected to increase. An expectation of share growth of **0%** for this company is reasonable.

TE – TECO Energy - TE's sustainable growth rate averaged 2.97% over the five-year historical period, with higher results in 2010. Absent negative results in 2008, the historical average growth was 3.79%. VL projects that the internal growth will, rebound through 2014-16, bringing sustainable growth to 5.6%. TE's book value, which increased at a 5% rate during the most recent five years, is expected to maintain that 5% rate in the future. That projected book value growth rate is slightly lower, but similar to growth indicated by the sustainable growth measure. TE's earnings per share are projected to increase at 10.5% (VL) to 4.9% (IBES), and 4.67% (Zack's) rates. Value Line's earnings growth expectation is predicated on the assumption of a 30% increase in TE's ROE. That growth rate would not be sustainable unless it is assumed that TE's ROE will increase 30% every five years into the indefinite future—an unlikely scenario. TE's dividends are expected to grow at a 4.5% rate, up considerably from negative 5% historically but below earnings growth expectations. Historically TE's earnings grew at a 12.5% rate, according to Value Line. The compound earnings growth over the past five years was only 2.13%, however. The projected sustainable growth indicate that investors can expect the growth from TE in the future to be higher than that which has existed in the past, and projected dividend growth confirms higher growth, but are below average earnings growth projections. Investors can reasonably expect a sustainable growth rate of **5.25%** for TE—well above historical averages.

Regarding share growth, TE's shares outstanding showed a 0.64% rate of increase over the past five years. TE's growth rate in shares outstanding is expected to show a 0.47% rate of increase through 2014-16. An expectation of share growth of **0.5%** for this company is reasonable.

ALE – ALLETE – ALE's sustainable growth rate has averaged 3.38% over the most recent five-year period, with much lower growth in the most recent year. VL expects ALE's sustainable growth to continue at a rate near historical averages and reach 3.8% by the 2014-16 period. ALE's book value growth rate is expected to be 3.5% over the next five years, lower than the 5% rate of growth experienced over the past five years. ALE's earnings per share are projected to increase at 6% according to Value Line, while IBES and Zack's project somewhat lower growth (5% IBES and Zacks). Value Line also projects a 2% growth in dividends, below the sustainable growth indications. Also Value Line shows historical earnings growth of 3.5% for this company. Investors can reasonably expect lower growth rate in the future, but not as high as the current earnings growth rate estimates—**3.75%** for ALE is reasonable.

Regarding share growth, ALE's shares outstanding increased at approximately a 4% rate over the past five years, due to an equity issuance in 2009. The number of shares is expected to grow at a 2.24% rate through 2014-16. An expectation of share growth of **3%** for this company is reasonable.

AEP- American Electric Power- AEP's sustainable growth rate has averaged 4.74% over the most recent five-year period. VL expects AEP's sustainable growth to decrease slightly to a level of 4.62% by the 2014-2016 period; showing overall stability. AEP's book value growth rate is expected to increase at a 5% rate over the next five years, equal to the 5% book value growth over the past five years. Both sustainable growth and book value growth point to relative growth rate stability for this company. AEP's earnings per share are projected to increase at 4.5% (VL), to 3.23% (IBES) and 4% (Zack's)—all below the indicated projected internal growth rate, but in relatively close agreement. Also, AEP's dividends are expected to grow at 4.0%. The average projected earnings, dividends and book value for this company is 4.50%. Investors can reasonably expect a sustainable growth rate in the future of **4.25%** for AEP.

Regarding share growth, AEP's shares outstanding increased at a 4.93% rate over the past five years, due to an equity issuance in 2009. Prior to 2009, the number of shares outstanding increased at a 1% rate. The number of shares outstanding in 2014-2016 is expected to show about a 0.79% increase from 2010 levels. An expectation of share growth of **1.75%** for this company is reasonable.

CNL – Cleco Corp. - CNL's sustainable growth rate averaged 4.10% for the five-year period, with the results in the most recent year above that average. VL expects sustainable growth to continue at a near-4% level through the 2014-16 period. CNL's book value growth is expected to increase at a 6.5% rate, well below the historical level of 11.0%, established during the building of a new generating plant, but above sustainable growth indications. CNL's earnings per share are projected to show 6.0% growth over the next five years, according to Value Line (IBES projects 3% earnings growth & Zacks earnngs projections were not available for this company). Historically CNL's earnings increased at a 7.5% rate, according to Value Line. CNL's dividend growth, which has held to 0.5% over the past five years is expected to expand to 9.5% over the next three- to five-year period as management expects to increase the payout ratio. The sustainable growth data indicate that future growth will be similar to prior growth rate averages, at lower overall levels than indicated by earnings growth projections, and would moderate future growth expectations somewhat. Investors can reasonably expect sustainable growth from CNL to be above past averages, a sustainable internal growth rate of **6.0%** is reasonable for this company.

Regarding share growth, CNL's shares outstanding grew at approximately a 1.26% rate over the past five years. The growth in the number of shares is expected by VL to be 0.06% through 2014-16. An expectation of share growth of **0.5%** for this company is reasonable.

ETR – Entergy Corp. - ETR's internal sustainable growth rate has averaged 7.79% over the most recent five-year period (2006-2010). Sustainable growth is expected to decline to about 4.85% by the 2014-2016 period. However, ETR's book value growth rate is expected to be 5.5% over the next five years—an increase from the 4% rate of growth experienced over the past five years—pointing to higher growth expectations for the future. The projected and historical book value growth (5.5% and 4%) bracket the projected sustainable growth, 4.85%, for this company. ETR's earnings per share are projected to increase at a rate of from 0.5% (VL), 2% (Zack's) to negative 3.5% (IBES). ETR's dividends are expected to grow at a 2.0% rate, down from an historical rate of 10.5%-- a substantial decline, moderating long-term growth expectations. Over the past five years, ETR's earnings grew at a 10% rate according to Value Line. Five-year historical compound earnings growth was lower, at 6.66%. Value Line's average earnings, dividend and book value growth rate for this company is 2.67%. These data indicate that investors can reasonably expect a sustainable growth rate in the future below past averages. Therefore, **4.75%** is a reasonable long-term growth expectation for ETR.

Regarding share growth, ETR's shares outstanding grew at a –3.09% rate over the past five years. The number of shares outstanding is projected by VL to decrease at a 0.77% rate through 2014-16. An expectation of share growth of **0%** for this company is reasonable.

WR – Westar Energy, Inc.- WR's sustainable growth rate has averaged 2.51% over the most recent five-year period, with lower growth in recent years. However, Value Line expects WR's sustainable growth to increase to 4% by the 2014-2016 period. However, WR's book value growth rate is expected to be

2.5% over the next five years, down substantially from the 6% rate of growth experienced over the past five years, and below sustainable growth projections. Also, WR's earnings per share are projected to increase at a rate of from 8.5% (Value Line), to 5.2% (IBES), to 6.09% (Zack's). The 8.5% earnings growth projected by Value Line includes the assumption that ROE will increase 33%. Over the past five years, WR's earnings growth was 1% according to Value Line. Compound 5-year historical earnings growth over the past five years for WR was negative 1.4%. Historically, dividends grew at a 7% rate, and Value Line expects that rate to decline to 3.0% over the next five years. The average earnings dividends and book value growth for WR, as published by Value Line is 4.67%. Investors can reasonably expect a higher sustainable growth over the long term — **4.5%** for WR is reasonable.

Regarding share growth, WR's shares outstanding increased at about a 6.4% rate over the past five years. The number of shares is expected to increase at a 2.68% rate through 2014-16. An expectation of share growth of **3.25%** for this company is reasonable.

AVA – Avista Corporation - AVA's sustainable growth rate has averaged 3.3% over the most recent five-year period (2006-2010). However, VL expects AVA's sustainable growth to decline below that historical growth rate level, and to reach 2.7% by the 2014-2016 period. AVA's book value growth rate is expected to be 3.0% over the next five years, also below the 4% rate of growth experienced over the past five years—indicating lower growth for this company. AVA's earnings per share are projected to increase at 4.5% (Value Line), 4.5% (IBES), and 4.67% (Zack's) rate. The company's dividends are expected to show 9% growth over the next five years, increasing long-term growth expectations. Investors can reasonably expect a sustainable growth rate in the future of **4.5%** for AVA.

Regarding share growth, AVA's shares outstanding grew at a 2.13% rate over the past five years. The number of shares is projected by VL to show a 1.32% rate of increase through the 2014-16 period. An expectation of share growth of **1.5%** for this company is reasonable.

HE – Hawaiian Electric - HE's sustainable growth rate has averaged -0.7% over the most recent five year period (2006-2010). However, VL expects HE's sustainable growth to increase from that historical growth rate level to reach approximately 3.7% by the 2014-2016 period. HE's book value growth rate is expected to be 3.5% over the next five years, up significantly from the 1% rate of growth experienced over the past five years. HE's earnings per share are projected to increase at an 11.0% (Value Line) to 8.03% (Zack's) to 13.1% (IBES) rate. Underlying those 3- to 5-year earnings growth projections is the assumption of the earned return increasing 60% from 6.7% in 2008-2010 to 10.5% in 2014-2016. That sort of increase in earned return is not sustainable for the indefinite future (i.e., it is unlikely that the earned ROE could continue to increase 60% every five years), and those earnings projections would not represent investors' expectations of the long-term sustainable rate of growth required in the DCF. HE's dividends are expected to show 1% growth over the next five years, moderating long-term growth expectations. Over the past five years, HE's earnings grew at a -6% rate, according to Value Line, while its dividends showed no increase, though the company maintained its dividend payment to investors. Investors can reasonably expect a sustainable growth rate in the future of **4.00%** for HE.

Regarding share growth, HE's shares outstanding grew at a 3.83% rate over the past five years due mainly to an equity issuance in 2008. Prior to that, the shares outstanding grew at a 1.5% rate. The number of shares is projected by VL to show a 3.04% rate of increase through the 2014-16 period. An expectation of share growth of **3.0%** for this company is reasonable.

PCG – PGE Corporation – PCG's sustainable growth rate has averaged 5.45% over the most recent five-year period, with 3.4% growth in the most recent year. VL expects PCG's sustainable growth to reach 5.5% through the 2014-16 period, showing stable growth. PCG's book value growth rate is expected to be 5.0% over the next five years, down substantially from the 10.5% rate of growth experienced over the past five years indicating moderating growth in the future. Projected book value growth is, however, similar to sustainable internal growth projections. Also, PCG's earnings per share are projected to increase at 5% according to Value Line (1.45% IBES and 4.27% Zacks). Value Line also projects a 3.0% growth in dividends, which are recovering from a dividend omission during the previous five years, but are below the sustainable growth indications. Investors can reasonably expect a stable sustainable growth rate in the future, but not as high as the current earnings growth rate estimates— **5.25%** for PCG is reasonable.

Regarding share growth, PCG's shares outstanding increased at approximately a 3.2% rate over the past five years. The number of shares is expected to grow at a 1.46% rate through 2014-16. An expectation of share growth of **2.0%** for this company is reasonable.

PNW — Pinnacle West - PNW's sustainable growth rate has averaged 1.84% over the most recent five-year period with higher growth in the most recent year. VL expects PNW's sustainable growth to rise above that historical average growth rate level to almost 3% by the 2014-2016 period. PNW's book value growth rate is expected to be 2.5% over the next five years, greater than the 0.5% rate of book value growth experienced over the past five years. PNW's earnings per share are projected to increase at a 6% (VL) to 5.6% (IBES) to 5.33% (Zack's) rate, with all projections above the indicated internal growth rate. PNW's dividends are expected to grow at a 2.0% rate, supporting much more moderate long-term growth rate expectations. Over the past five years, PNW's earnings growth was 0.5% while its dividends increased at a 3% rate. The average Value Line projected growth rate for this company is 3.50%. Investors can reasonably expect a sustainable growth rate in the future of **3.5%** for PNW.

Regarding share growth, PNW's shares outstanding increased at a 2.13% rate over the past five years. The number of shares outstanding in 2014-2016 is expected to show a 2.49% increase from 2010 levels. An expectation of share growth of **2.25%** for this company is reasonable.

POR – Portland General- POR's sustainable growth rate has averaged 3.05% over the most recent five-year period. Value Line expects POR's sustainable growth to increase to 4.2% by the 2014-2016 period. POR's book value growth rate is expected to be 3.0% over the next five years, below sustainable growth projections, but above historical book value growth (2%). Also, POR's earnings per share are projected to increase at a rate of from 7.5% (Value Line), to 5.9% (IBES), to 5.0% (Zack's). Value Line reports historical earnings, and book value growth for this company of 7.5%, and 2%. The average Value Line projected earnings, dividend and book value growth is 4.5%. Investors can reasonably expect a higher sustainable growth over the long term **— 4.25%** for POR is reasonable.

Regarding share growth, POR's shares outstanding increased at about a 4.8% rate over the past five years, due to an equity issuance in 2009. Prior to that annual share growth was very low (0.04%). The number of shares is expected to increase at a 0.25% rate through 2014-16. An expectation of share growth of **1.0%** for this company is reasonable.

UNS – UniSource Energy - UNS's sustainable growth rate has averaged 4.05% over the most recent five-year period, including a negative year in 2008. Value Line expects UNS's sustainable growth to increase to approximately 4.95% by the 2014-2016 period. Also, UNS's book value growth rate is expected to be 5% over the next five years, similar to the 4.5% rate of growth experienced over the past five years, and approximately equal to sustainable growth projections. UNS's earnings per share are projected to increase at a rate of from 9.5% (Value Line), to 3% (IBES) and 2.6% (Zack's)—a wide range. Over the past five years, UNS's earnings growth was 8.5% according to Value Line. Historically, dividends grew at a 13% rate, but Value Line expects that rate to decline to 9% over the next five years. Investors can reasonably expect a higher sustainable growth over the long term **— 5.5%** for UNS is reasonable.

Regarding share growth, UNS's shares outstanding increased at a 0.95% rate over the past five years. The number of shares is expected to increase at a 0.79% rate through 2014-16. An expectation of share growth of **0.75%** for this company is reasonable.

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF KENTUCKY POWER	)
COMPANY FOR APPROVAL OF ITS 2011	)
ENVIRONMENTAL COMPLIANCE PLAN, FOR	)
APPROVAL OF ITS AMENDED	)
ENVIRONMENTAL COST RECOVERY	) CASE NO. 2011-00401
SURCHARGE TARRIFF, AND FOR THE GRANT	)
OF A CERTIFICATE OF CONVENIENCE AND	)
NECESSITY FOR THE CONSTRUCTION AND	)
ACQUISITION OF RELATED FACILITIES	)

DIRECT TESTIMONY

OF

STEPHEN G. HILL

ON BEHALF OF

THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS

MARCH 2, 2012

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DIRECT TESTIMONY

STEPHEN G. HILL

CASE NO. 2011-00401
KENTUCKY POWER COMPANY

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I. INTRODUCTION / SUMMARY

Q. PLEASE STATE YOUR NAME, OCCUPATION AND ADDRESS.

A. My name is Stephen G. Hill. I am self-employed as a financial consultant, and principal of Hill Associates, a consulting firm specializing in financial and economic issues in regulated industries. My business address is P.O. Box 587, Hurricane, West Virginia, 25526 (e-mail: hillassociates@gmail.com).

Q. BRIEFLY, WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. After graduating with a Bachelor of Science degree in Chemical Engineering from Auburn University in Auburn, Alabama, I was awarded a scholarship to attend Tulane Graduate School of Business Administration at Tulane University in New Orleans, Louisiana. There I received a Master's Degree in Business Administration. I have been awarded the professional designation "Certified Rate of Return Analyst" by the Society of Utility and Regulatory Financial Analysts. This designation is based upon education, experience, and the successful completion of a comprehensive examination. I have also been on the Board of Directors of that national organization for several years. A more detailed account of my educational background and occupational experience appears in Appendix A.

Q. HAVE YOU TESTIFIED BEFORE THIS OR OTHER REGULATORY COMMISSIONS?

A. Yes, I have testified previously before this Commission. In addition, over the past 30 years I have testified on cost of capital, corporate finance and capital market issues in more than 275 regulatory proceedings before the following regulatory bodies: West Virginia Public Service Commission, Pennsylvania Public Utilities Commission, the Oklahoma State Corporation Commission, Public Utilities Commission of the State of

California, Texas Public Utilities Commission, Maryland Public Service Commission, Public Utilities Commission of the State of Minnesota, Ohio Public Utilities Commission, Insurance Commissioner of the State of Texas, North Carolina Insurance Commissioner, Rhode Island Public Utilities Commission, City Council of Austin, Texas, Texas Railroad Commission, Arizona Corporation Commission, South Carolina Public Service Commission, Public Utilities Commission of the State of Hawaii, New Mexico Corporation Commission, Virginia Corporation Commission, Massachusetts Department of Public Utilities, State of Washington Utilities and Transportation Commission, Georgia Public Service Commission, Public Service Commission of Utah, Illinois Commerce Commission, Kansas Corporation Commission, Indiana Utility Regulatory Commission, Washington Utilities and Transportation Commission, Montana Public Service Commission, Public Service Commission of the State of Maine, Public Service Commission of Wisconsin, Vermont Public Service Board, Federal Communications Commission and Federal Energy Regulatory Commission. I have also testified before the West Virginia Air Pollution Control Commission regarding appropriate pollution-control technology and its financial impact on the company under review and have been an advisor to the Arizona Corporation Commission on matters of utility finance.

O. ON BEHALF OF WHOM ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am appearing on behalf of the Kentucky Industrial Utility Customers, Inc. (KIUC).

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. In these proceedings, Kentucky Power Company (Kentucky Power, KPCO), a subsidiary of American Electric Power Company (AEP), is requesting a surcharge to recover the costs of planned environmental construction. The environmental surcharge allowed pursuant to Section 278.183 of the Kentucky Code includes "a reasonable return on construction." Utility construction is normally undertaken using monies provided predominantly through the issuance of short-term debt, which is ultimately replaced with a mix of long-term capital. This means of financing utility construction is the most economical (least expensive) to the utility and to its customers as well. Therefore a reasonable or normal cost associated with utility construction is that of short-term debt.

The Companies have requested that the return aspect of the environmental surcharge be calculated using KPCO's overall cost of capital. That overall cost of capital requested by the Companies is based on an after-tax equity return of 10.50% and a capital structure consisting of 53.48% common equity and 46.52% debt.[1,2] According to the testimony of the Company's witness Lila Munsey, the return on equity requested by the Company is that determined in the settlement its most recent rate case (Docket No. 2010-00020).

My testimony presents the results of studies I have performed related to the determination of the cost of capital for the integrated electric utility operations of KPCO. That analysis shows that, by relying on a 10.50% return on equity capital, the Company has significantly overstated the current cost of common equity for integrated electric utility operations similar in risk to KPCO.

Moreover, in their requested overall return, the Companies have ignored the fact that the return recovery method utilized in the environmental surcharge mechanism, which allows recovery of costs during construction only two months after those costs are incurred, represents a very low-risk alternative to the normal used-and-useful regulatory paradigm. In a normal utility plant construction process, the company is not allowed to recover the costs associated with construction until that plant is "used and useful," in the same way an auto manufacturer is unable to recover the costs of building a new production facility until cars are rolling off the assembly line and the cars are sold.

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[1] Testimony of Company witness Munsey, Exhibit LPM-3, ROE based on that approved in Docket No. 2010-00020, capital structure: 56.065% debt and 42.943% equity.

[2] On a pre-tax, ratemaking basis, the Company's requested equity return is 16.55% (10.50% ÷ (1-36.56% tax rate). A 36.56% tax rate is equivalent to the 1.5762 Gross Revenue Conversion factor used in Docket No. 2010-00020.

The ability of KPCO to recover, through a surcharge to customers, the total cost of environmental construction just two months following cost incurrence, including a return and prior to the completion of the construction project represents a lower operational risk than normal rate base/rate of return utility operations. As a result, if the Commission elects to base its allowed return included in the environmental surcharge on the Company's overall return, the return on equity included in that overall return calculation should be at the lower end of a reasonable range in order to account for the lower risk afforded by the environmental surcharge.

Finally, it is especially important in these difficult economic times of high unemployment that, if the Companies are afforded low-risk treatment in the manner in which they are allowed to recover mandated environmental costs, then that lower operational risk should also provide a benefit for the Company's customers and be passed on by means of a lower allowed return in the surcharge.

In summary, if the Commission elects to use an overall return to calculate the Company's environmental surcharge, then KIUC recommends that the Commission recognize that the current cost of equity capital is below the 10.50% requested by the Companies and, further, that the allowed return be set at the lower end of a reasonable range to account for the low-risk nature of the manner in which environmental construction costs are recovered in Kentucky.

Q. HAVE YOU PREPARED AN EXHIBIT IN SUPPORT OF YOUR TESTIMONY?

A. Yes, Exhibit_(SGH-1) consists of 12 Schedules and provides the analytical support for the conclusions reached regarding the cost of common equity, capital structure and overall cost of capital for KPCO presented in the body of the testimony. This Exhibit was prepared by me and is correct to the best of my knowledge and belief. Also, I have provided four Appendices ("A" through "C"), which contain additional detail regarding certain aspects of my narrative testimony in this proceeding.

Q. PLEASE SUMMARIZE YOUR TESTIMONY AND FINDINGS CONCERNING THE RATE OF RETURN THAT SHOULD BE UTILIZED IN SETTING RATES FOR KPCO'S ENVIRONMENTAL SURCHARGE IN THESE PROCEEDINGS.

A. My testimony is organized into three sections. First, I review the current economic environment in which my equity return estimate is made and evaluate the current state of that environment in light of the financial crisis underway during the Company's last rate proceedings.

Second, I review the Company's capital structure and the average capital structure existing in the electric utility industry in order to determine an appropriate capital structure for rate-making purposes.

Third, I evaluate the cost of equity capital for utility operations that are similar in risk to KPCO using Discounted Cash Flow (DCF), Capital Asset Pricing Model (CAPM), Modified Earnings-Price Ratio (MEPR), and Market-to-Book Ratio (MTB) analyses.

The current cost of equity capital for electric utility firms of similar risk to KPCO falls in a range of 9.00% to 9.75%. Moreover, because Kentucky law allows the Companies to recover investments in environmental plant during the construction phase with only a two-month lag, investment in environmental plant is low compared to normal utility plant investment. Therefore, the return afforded the Companies for their environmental surcharge should be in the lower end of that reasonable range, or 9.0%-9.375%.

Applying the mid-point of that 9.0%-9.375% equity capital cost range (9.2%) to KPCO's requested capital structure and embedded cost rates indicates overall capital costs of 7.41%. Those overall costs of capital afford the Companies the opportunity to achieve pre-tax interest coverage levels on their environmental plant investment of 2.87 times for KPCO, respectively. (See Exhibit__(SGH-1), Schedule 12) In other words, allowed a 9.2% return on the equity portion of their investment in environmental plant, the Companies have the opportunity to earn an amount of net income on that plant that is approximately 2.87 times greater than the interest costs incurred. This level of interest coverage exceeds KPCO's average interest coverage over the 2008-2020 period, 2.13 times, according to data available in the Company's 2010 Annual Report published on AEP's website. [3] The overall return I am recommending, then, is sufficient to maintain the Company financial integrity and meets the requirements of *Hope* and *Bluefield*.

Q. IS THERE INDEPENDENT EVIDENCE IN THE RECORD IN THIS PROCEEDING THAT CONFIRMS THE REASONABLNESS OF YOUR EQUITY COST ESTIMATE FOR KPCO?

A. Yes. At page 31 of its 2010 S.E.C. Form 10-K, KEPCO's parent company, AEP, indicates that one-half of its pension fund retirement portfolio (totaling approximately $4 Billion) is comprised of investments in common equity. In addition, AEP informs its investors that over the long term it expects to earn a return on its equity investments of 9.0%. This expected return on equity is for common stocks in general or the broad market for stocks, not for utility stocks, which have lower risk than the market. This information confirms that investors' equity return expectations (and the cost of equity capital to a firm) are modest.

In addition, based on the Company's long-term return expectations for their own equity investments, my estimate for the cost of equity capital for companies similar in risk to KPCO of 9.0% to 9.75% is conservative. It is conservative because electric utilities are less risky investments than U.S. equities as a whole (which is the basis for the Company's return expectations). Therefore, if the Company's long-term equity return expectation of 9.0% for U.S. stocks is representative of investor expectations, then a reasonable expected return for electric utilities would be below that level. The Company's expected return on its own equity investments in the U.S. stock market falls

[3] http://www.aep.com/investors/financialfilingsandreports/edgar/kentuckypower.aspx

below my estimated range for the cost of equity capital for electric utilities, indicating that my equity cost estimate is, at the very least, reasonable, and should be considered conservative.

Q. MR. HILL, ISN'T IT REASONABLE TO BELIEVE THAT PENSION FUND RETURN EXPECTATIONS ARE MODERATE (LOWER) IN ORDER TO AVOID OVERSTATEMENT OF THE FUTURE VALUE AND SUBSEQUENT UNDER-FUNDING OF THE FUND?

A. Yes. Neither the Companies nor their investment managers would use equity return expectations that are too high for its pension fund assets because that would overstate the expected future value of that fund. If the expected returns are overstated, the current funding requirement would be understated and the firm would be left with unfunded pension liabilities that could add unnecessarily to its financial risk profile.

However, it is also reasonable to believe that the Company would not significantly under-estimate the pension fund return estimates, either. Under-estimating the expected return would call for an unnecessarily high annual contribution every year to reach the future targeted amount of pension funds. Any unnecessarily large annual pension expense would reduce profitability—an undesirable outcome for any company. In addition, if ultimate returns turn out to be higher than predicted through under-estimating the portfolio return, the firm will, effectively, have funded its pension requirements with internally generated funds that could have been put to other uses such as production, distribution, or required environmental facilities. Also, the Company is relying on the advice of its portfolio investment mangers and that investment firm's assessment of long-term equity return expectations for the U.S., who would have no interest in "shading" the return expectation in either direction.

Therefore, because there are negatives associated with either over- or under-stating expected pension portfolio returns, it is reasonable to assume that KPCO management (as well as AEP management) seeks to accurately estimate its expected investment returns and believes that, over the long-term, the common equity return expectations for its pension fund investments are in the 9.0% range, cited above.

Q. WHY SHOULD THE COST OF CAPITAL SERVE AS A BASIS FOR THE PROPER ALLOWED RATE OF RETURN FOR A REGULATED FIRM?

A. The Supreme Court of the United States has established, as a guide to assessing an appropriate level of profitability for regulated operations, that investors in such firms are to be given an opportunity to earn returns that are sufficient to attract capital and are comparable to returns investors would expect in the unregulated sector for assuming the same degree of risk. The *Bluefield* and *Hope* cases provide the seminal decisions (*Bluefield Water Works v. PSC*), 262 US 679 [1923]; *FPC v. Hope Natural Gas Company*, 320 US 591 [1944]). These criteria were restated in the *Permian Basin Area Rate Cases,* 390 US 747 (1968). However, the Court also makes quite clear in *Hope* that regulation does not guarantee profitability and, in *Permian Basin*, that, while investor interests (profitability) are certainly pertinent to setting adequate rates, those interests do not exhaust the relevant considerations.

As a starting point in the rate-setting process, then, the market-based cost of capital of a regulated firm represents the return investors could expect from other investments, while assuming no more and no less risk. Because financial theory holds that investors will not provide capital for a particular investment unless that investment is expected to yield the opportunity cost of capital, the correspondence of the cost of capital with the Court's guidelines for appropriate earnings is clear.

Q. THE COST OF EQUITY CAPITAL IS OFTEN ESTIMATED USING A COMPLEX ARRAY OF ECONOMIC MODELS AND ALGEBRAIC FORMULAS. IS THERE A SIMPLE WAY TO UNDERSTAND THE CONCEPT OF THE COST OF EQUITY CAPITAL?

A. Yes. In a regulated ratemaking context such as this, the cost of equity capital can be most easily understood as the percentage profit that should be allowed for the regulated firm. A firm's profit is the amount of money that remains from its revenues after a firm has paid all of its costs—operating costs (commodity supply costs, depreciation, equipment maintenance costs, salaries, fees, retirement obligations, property taxes), as well as income taxes and interest costs. That dollar amount of profit, divided by the book value of the common equity capital used to finance the firm's regulated assets equals the percentage rate of return on equity. If, for example, the profit earned by a utility is $10/year and the firm has $100 of equity capital on its books, the firm's earned return on equity (ROE), or it's profit, is 10%.

The purpose of all of the economic models and formulas in cost of capital testimony is to estimate, using market data of similar-risk firms, the market-based rate of return equity investors require for a particular risk-class of firms—in this case, electric utility operations. If the profit allowed in the ratemaking process, as a percent of the firm's equity capital, is set equal to the cost of equity capital (the investors' required market-based return), the utility, under efficient management, will be able to attract the capital necessary to maintain the firm's financial integrity, and the interests of investors and ratepayers will be balanced, as called for in the U.S. Supreme Court cases cited above.

Simply put, the amount of profit the utility should be allowed the opportunity to earn, as a percentage of the total equity investment, should be equal to the cost of equity capital.

II. ECONOMIC ENVIRONMENT

Q. WHY IS IT IMPORTANT TO REVIEW THE ECONOMIC ENVIRONMENT IN WHICH AN EQUITY COST ESTIMATE IS MADE?

A. The cost of equity capital is an expectational, or *ex ante*, concept. In seeking to estimate the cost of equity capital of a firm, it is necessary to gauge investor expectations with regard to the relative risk and return of that firm, as well as that for the particular risk-class of investments in which that firm resides. Because this exercise is, necessarily, based on understanding and accurately assessing investor expectations, a review of the larger economic environment within which the investor makes his or her decision is most important. Investor expectations regarding the strength of the U.S. economy, the direction of interest rates and the level of inflation (factors that are determinative of capital costs) are key building blocks in the investment decision. The analyst and the regulatory body should review those factors in order to assess accurately investors' required return—the cost of equity capital to the regulated firm.

Q. WHAT ARE THE INDICATIONS WITH REGARD TO THE COST OF CAPITAL IN THE CURRENT ECONOMIC ENVIRONMENT?

A. Although three years have passed since the events of late 2008 and early 2009, any review of the current economic environment and the current cost of capital must take into account what was the most significant disruption in the financial markets since the Great Depression in the 1930s. In the tumultuous economic environment that existed during the third and fourth quarters of 2008 and early 2009, the signals with regard to the cost of capital were difficult to discern. Stock prices fell dramatically, increasing dividend yields, which would indicate increasing capital costs if expected growth rates were constant. However, fundamental indicators of capital cost rates—long-term U.S. Treasury bond yields—declined, signaling that investors actually required and expected lower returns during that difficult economic time.

As shown in Chart I below, there have been wide fluctuations in *short-term* interest rate levels over the past ten years as the Federal Reserve Board (the Fed) raised and lowered the Federal Funds rate to slow down and encourage (respectively) economic growth. However, *long-term* interest rates have ranged from 4.5% to 5.5% over most of that time, with a slow downward trend. As a result of that 2008/2009 economic downturn, long-term Treasury bond yields dipped, for a time, below the lower end of that historical range as investors turned to bonds as a safe haven. As the economic downturn moderated and a modest recovery began to appear, long-term T-bond yields returned to their historical trend.

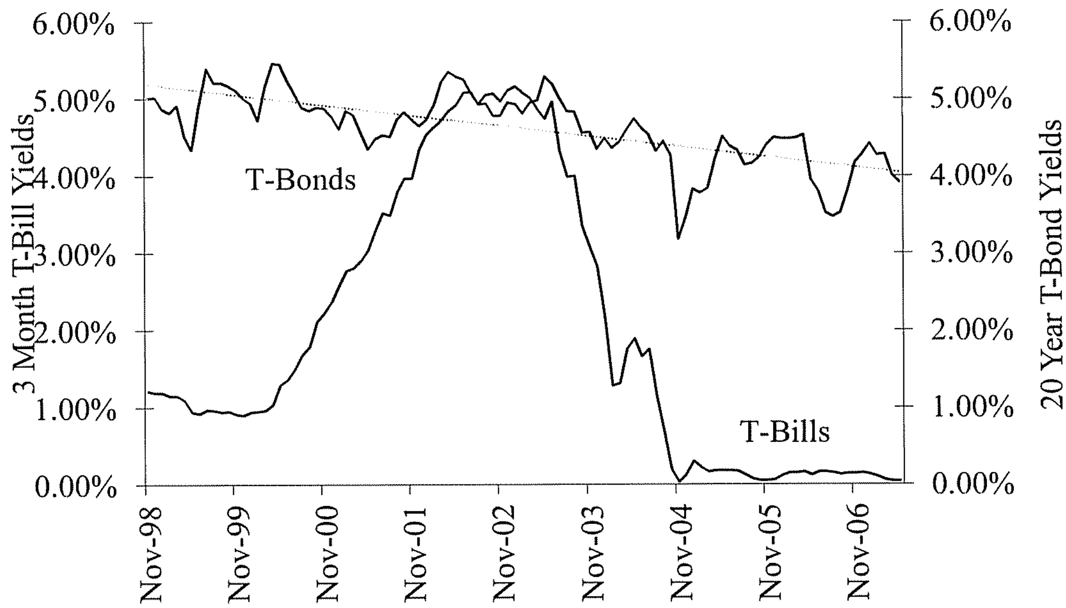
More recently, with new concerns about the international banking industry, centered primarily with the smaller economies in the European Union, long-term Treasury rates have again taken a dip below historical trends. That drop in Treasury yields results, again, from investors turning to U.S. Treasuries as reliable and safe investments. According to the most recent Federal Reserve Statistical Release H.15, the average 30-year T-Bond yield in November 2011 was only 3.0%.[4]

The interest rate data in Chart I on the next page also indicate that the Fed lowered short-term interest rates to near zero to attempt to lessen the impact of the recession and, continues to take a very accommodative stance regarding monetary policy, with short-term T-Bills yielding a near zero. (The average 3-month T-Bill rate in December 2011 was only 0.01%.) As a result, fundamental long-term capital costs have not increased as a result the financial crisis in 2008/09 and, in fact, are currently somewhat below the long-term downward trend in capital costs begun prior to the financial crisis.

[4] http://www.federalreserve.gov/Releases/H15/Current/, December 15, 2011.

Chart I.

Relative Interest Rate Changes



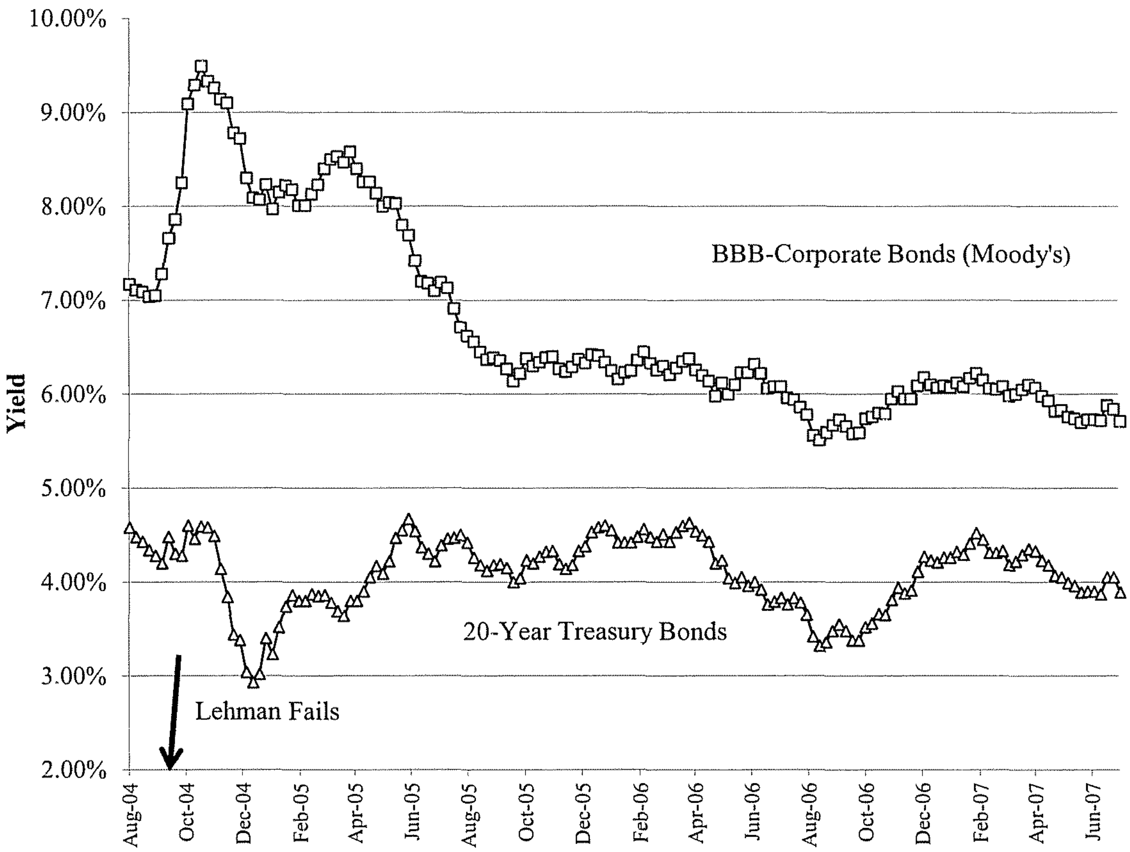
Data from Federal Reserve Statistical Release H.15

Because the market for U.S. Treasury securities remained liquid throughout the 2008/09 financial crisis and because the liquidity problems existing during that crisis eventually subsided, it is reasonable to believe that the yields on long-term Treasuries are representative of investors' general long-term risk-free return expectations. Absent the recent downturn in T-Bond yields due to international banking concerns, the trend in long-term T-Bond yields, as shown in Chart I, above, indicates a current "normative" long-term risk-free yield expectation of approximately 4%. Therefore, this fundamental building block of capital costs (long-term T-bond yields) provides an indication that in the current economic environment, capital costs are lower than they were prior to the economic troubles of late 2008 and early 2009.

However, it is also important to note that a review of corporate bond yield history indicates that, during the financial crisis of 2008/2009 declining yields was not the case with corporate bonds. Following the demise of Lehman Brothers and the near-collapse of the financial community in the U.S. and abroad due to enormous debt obligations related to mortgage-back securities and credit default swaps—even with the commitment of government support of the successor financial institutions—there was a temporary lack of liquidity in the corporate sector of the bond market. The banks, investment brokerage firms, and other institutional investors were holding on to capital in order to shore up their own balance sheets rather than re-injecting those monies into the financial system through lending (buying corporate debt). As a result, even though the Fed was driving down short-term Treasury rates to provide additional liquidity for the economy in general, that liquidity was not passed through to the corporate bond market and, with a lack of capital supply, corporate bond yields increased in late 2008 and early 2009. The relative movement of BBB-rated corporate bond yields and U.S. Treasury yields is shown in Chart II, on the next page.

Chart II

Financial Crisis: Bond Yield Changes



Following the failure of Lehman Brothers, as the full extent of the debt/derivative risk overhang in the financial industry became known, BBB-rated corporate bond yields increased, even as long-term Treasury yields remained relatively steady at about 4.5%. According to the database of the Federal Reserve, BBB-rated corporate bond yields rose dramatically by 250 basis points as the risk of default, and the nervousness of investors increased and, as a result the spread between corporate bonds and U.S. Treasuries widened to about 4%—approximately double the more normal 2%.

As liquidity began to be restored to the bond markets, initially through direct government intervention and subsequently through the return of modestly positive economic growth, corporate bond yields have declined substantially from the highs established in the fall of 2008. More recently, investors' concerns have eased, the stock market has rebounded (exceeding the 12,000 mark), and corporate bond yields have declined below pre-crisis levels. As a result, the yield spread differential between corporate bonds and long-term Treasury securities declined to a more normal level. Therefore, because both the absolute level of the risk-free rate and the yield spread between Treasury bonds and corporate bonds have declined since the financial crisis, any concern that the 2008/09 financial crisis implies continuing financial difficulty for utilities would be an incorrect assessment.

Chart II also shows that bond yield spreads have increased somewhat since September of 2011 due to the European bank default concerns (the BBB Corporate-to-20-year T-Bond yield spread in November 2011 was approximately 2.5%; 50 basis points higher than normal). However, that increase is due to the decline in T-Bond yields, not an increase in corporate yields. In fact, BBB-rated corporate yields have also recently declined, just not as rapidly as long-term Treasuries.

For example, for BBB-rated utilities, Value Line reports that 25/30-year bonds are yielding an average of 4.84% over the most recent six-week period. One year ago, BBB-rated utility bonds were providing average yields of 5.97%—more than 100 basis points higher.[5] Therefore, in terms of relative capital costs, the broad economic environment currently is more benign than it was prior to the financial crisis—capital costs are lower—and, thus, more favorable for capital intensive industries like utilities.

On balance, then, the fixed-income data available in the financial marketplace indicate that while there were technical difficulties in the corporate bond market that drove up yields for a period of time, those difficulties have not proven to be a long-term phenomenon and the high corporate bond yields experienced in the latter part of 2008 and early 2009 do not represent investors' long-term expectations. Those data also indicate

[5] The Value Line Investment Survey, *Selection & Opinion*; the most recent six weekly editions: November 11 through December 16, 2011.

that investors' required return for a risk-free investment remains low by historical standards. Finally, those data available in the marketplace indicate that the most recent unease regarding international banking has had only a modest effect on bond yield spreads, which is due to the safe-haven aspect of U.S. Treasuries and not higher yields for corporate bonds. Therefore, the bond yield data available in the market place indicates that the risk-free rate of return, a fundamental element of all capital costs has declined from pre-crisis levels, corporate bond yields have declined well below pre-crisis levels, and indicate a lower cost of capital in the current economic environment.

Q. WHAT IS THE CURRENT EXPECTATION WITH REGARD TO THE ECONOMY AND INTEREST RATES?

A. As Value Line notes in its most recent Quarterly Economic Review, the current expectation for the U.S. economy is that recovery from the recent economic recession is likely to continue to be slow, but the economy will eventually expand at a moderate pace with the aid of accommodative Federal Reserve credit policy. Moreover, the Fed is expected to keep interest rates low until the economic recovery becomes more robust.

> **Economic Growth:** As noted the nation's economy pressed forward by 2.5% in the third quarter. Now, taken by itself, that was not a memorable performance, as it was still a percent, or so, below the rate generally seen as needed to measurably reduce the 9.0% jobless rate. More important, it is likely that this moderately better economic pace is not sustainable. In fact, we expect growth during the final three months of this year to be and the first half of 2012 to ease back to 2%, or less, as business investment, which was so potent in the recent period, figures to be more restrained, along with consumer spending and export demand. [Chart omitted]
>
> Looking our, our economic model assumes that Europe will suffer no worse than a mild recession and the China and much of Asia will stay on a modest growth trajectory. Over here, a further rise in industrial production [Chart omitted],

> modest retail improvement [Chart omitted], progressively better payroll numbers and a gradual decline in the unemployment rate [Chart omitted], and a belated turnaround in the troubled U.S. housing market, where pent-up demand is becoming a key variable [Chart omitted] are all probable next year.
>
> **Inflation:** Worries here are easing, although that is hard to tell those who shop for food, fill up their cars with gas, or heat or cool their homes. On the whole, inflation at the producer (or wholesale) and consumer levels are now showing moderating gains this year. Meanwhile, there could well be limited pressure from oil and food in 2012, as GDP growth probably will be muted. Also, with listless business and consumer demand in 2012, there figures to be a pullback in commodity process and limited wage growht. That should help to keep the so-called core rate of inflation, which excludes energy and food, under control.
>
> **Interest Rates:** Interest rates have trended mostly lower since August's "Quarterly Economic Review," with yields on the benchmark 10-year Treasury note easing from 2.17% to 2.00%. Six months ago, such yields were up at 3.18%. At the same time, the yield on the companion 30-year Treasury bond has fallen from 3.56% three months ago to 3.00% recently. Six months ago, the 30-year bond was yielding 4.30%. Concerns about Europe, China, and our own ability to sidestep a recession have led to this "flight to quality," pushing down yields in the process....Looking further out, we sense interest rates will stay near their historic lows until well into 2013. [Chart omitted] (The Value Line Investment Survey, *Selection & Opinion*, November 25, 2011, pp. 1889-1890.)

In that most recent Quarterly Economic Review cited above, Value Line projects long-term Treasury bond rates will average 3.9% through 2012 and 4.1% in 2013. According to Value Line's *Selection and Opinion,* 30-year Treasury bond yields have averaged 3.01% over the most recent six weeks.[6] Therefore, the indicated expectation

[6] The Value Line Investment Survey, *Selection & Opinion*, "Selected Yields," 11/11/11 through 12/16/11.

with regard to long-term interest rates is that they expected move somewhat higher in the future, provided the economic recovery continues to advance at a moderate pace. Simply put, due to the moderate pace of the economy and relatively low core inflation, capital costs are low and are expected to remain low until the economy shows more rapid growth, at which time interest rates and capital costs are expected to increase moderately.

III. CAPITAL STRUCTURE

Q. WHAT CAPITAL STRUCTURES IS THE COMPANY USING IN ITS FILING IN THIS CASE?

A. The Company is using its April 30, 2010 capital structure, including financing from accounts receivable and the embedded cost rates. That capital structure consisted of 43.943% common equity, 4.116% accounts receivable and 51.941% long-term debt. The Company had no short-term debt outstanding.

Q. IS THE CAPITAL STRUCTURE USED BY THE COMPANY SIMILAR TO THE MANNER IN WHICH IT HAS BEEN RECENTLY CAPITALIZED?

A. Yes. The capital structure data from the Company's response to Data Request AG-31 is shown on Schedule 1 attached to this testimony. Those data also show that KPCO's common equity ratio over the most recent five quarters approximately 45% of total capital. The capital structures shown on Schedule 1 do not include accounts receivable, making the average common equity ratio slightly higher than would obtain if that source of funding were considered. These data show that the Company's requested capital structure is representative of the manner in which KPCO is currently capitalized.

Q. HOW DOES KPCO'S RECENT CAPITAL STRUCTURE COMPARE TO THAT UTILIZED IN THE ELECTRIC UTILITY INDUSTRY TODAY?

A. KPCO is capitalized similarly to the electric utility industry on average. As shown on Schedule 2 attached to my testimony, the average common equity ratio of the electric utility industry is 46.3%, and the median is 45.6%. KPCO's recent average capital structue is similar to that used, on average, in the electric utility industry. For that reason, KPCO has average financial risk for an electric utility.

In my cost of equity capital analysis, which follows this discussion of capital structure, I select a sample group of 13 electric and combination electric and gas companies similar in risk to KPCO for my cost of equity analysis. According to the Februray 2012 edition of *AUS Utility Reports*, those companies have a current average common equity ratio of 45.6%—again similar to KPCO's common equity ratio. Therefore, because my cost of equity estimate is based on companies that have a similar amount of common equity and similar financial risk, the cost of common equity estimate obtained in this analysis is appropriate for KPCO.

Q. THE CAPITAL STRUCTURES YOU SHOW ON YOUR SCHEDULE 2 ARE THOSE OF THE PUBLICLY TRADED UTILITY HOLDING COMPANIES, NOT THE UTILITY SUBSIDIARIES, CORRECT?

A. Yes.

Q. WHY ARE THOSE CAPITAL STRUCTURES APPROPRIATE FOR COMPARISON WITH THE RATE-MAKING CAPITAL STRUCTURE OF KPCO— A REGULATED UTILITY SUBSIDIARY?

A. In this proceeding, the Commission will base the allowed return on equity for KPCO on the market-based cost of capital estimates of other similar-risk, publicly traded electric companies. The publicly traded companies are the parent holding companies, not the individual regulated subsidiaries, and those publicly-traded parent companies (not the utility subsidiaries) are key to the cost of equity estimate. For example, in order to own an interest in a regulated utility, an investor must purchase shares of its parent company, and it is the financial risk inherent in the capital structure of that parent company to which the investor is exposed. Therefore, to assess the appropriate capital structure in a ratemaking proceeding (the capital structure that corresponds with the market-based cost of equity), we must turn to the capital structure of the publicly traded parent holding company, which is the capital structure of import to the investor that directly impacts the cost of common equity capital.

Q. WHICH CAPITAL STRUCTURE DO YOU RECOMMEND FOR DETERMINING THE RETURN PORTION OF THE ENVIRONMENTAL SURCHARGE AT ISSUE IN THIS PROCEEDING?

A. It is my understanding that this Commission has traditionally relied on the utility subsidiary's booked capital structure in determining an overall return for ratemaking purposes. For that reason, if this Commission elects to utilize an overall return (rather than the cost of short-term debt, which would more closely mirror the Company's actual capital costs during construction), because the Company's requested capital structure is very similar to the manner in which it has been recently capitalized, I recommend that KPCO's requested capital structure be used to determine the Company's overall return. That capital structure and embedded cost rates are shown on Company witness Munsey's Exhibit LPM-3, page 1.

Q. DOES THIS CONCLUDE YOUR DISCUSSION OF CAPITAL STRUCTURE?

A. Yes, it does.

IV. METHODS OF EQUITY COST EVALUATION

A. SAMPLE GROUP SELECTION

Q. PLEASE EXPLAIN WHY YOU ANALYZED THE MARKET DATA OF SEVERAL COMPANIES TO ESTIMATE THE COST OF EQUITY.

A. I have used the "similar sample group" approach to cost of capital analysis because it yields a more accurate determination of the cost of equity capital than the analysis of the data of only one company. Any form of analysis where the result is an estimate, such as growth in the DCF model, is subject to measurement error, *i.e.*, error induced by the measurement of a particular parameter or by variations in the estimate of the technique chosen. When the technique is applied to only one observation (*e.g.*, estimating the DCF growth rate for a single company) the estimate is referred to, statistically, as having "zero degrees of freedom." This means, simply, that there is no way of knowing if any observed change in the growth rate estimate is due to measurement error or to an actual change in the cost of capital. The degrees of freedom can be increased and exposure to measurement error reduced by applying any given estimation technique to a sample of similar-risk companies rather than one single company. Therefore, by analyzing a group of firms with similar characteristics, the estimated value (the growth rate and the resultant cost of capital) is more likely to equal the "true" value for that type of operation.

Q. HOW WERE THE FIRMS SELECTED FOR YOUR ANALYSIS?

A. As a basis for analysis, I analyzed the market data of electric and combination electric and gas companies with generation assets that also had at least 70% of revenues from electric operations, did not have a pending merger, did not have a recent dividend cut, had stable book values, and bond ratings between "A-" and "BBB-." The screening process for electric utilities is summarized on Schedule 3 attached to my testimony. All of the electric utilities followed by Value Line are shown, as well as the screening parameters and the parameter values for each company. The electric utility companies selected for my analysis as similar in risk to KPCO are: FirstEnergy Corp. (FE), TECO Energy (TE), ALLETE (ALE), American Electric Power (AEP), Cleco Corp. (CNL), Entergy Corp. (ETR), Westar Energy (WR), Avista Corporation (AVA), Hawaiian Electric Industries (HE), PGE Corporation (PCG), Pinnacle West Capital Corp. (PNW), Portland General (POR), and UniSource Energy (UNS).[7]

B. DISCOUNTED CASH FLOW MODEL

Q. PLEASE DESCRIBE THE DISCOUNTED CASH FLOW (DCF) MODEL YOU USED TO ARRIVE AT AN ESTIMATE OF THE COST RATE OF COMMON EQUITY CAPITAL FOR KPCO IN THIS PROCEEDING.

A. The DCF model relies on the equivalence of the market price of the stock (P) with the present value of the cash flows investors expect from the stock, and assumes that the discount rate equals the cost of capital. The total return to the investor, which equals the required return and the cost of equity capital according to this theory, is the sum of the dividend yield and the expected growth rate in the dividend.

The theory is represented by the equation,

$$k = D/P + g, \qquad (1)$$

where “k” is the equity capitalization rate (cost of equity, required return), “D/P” is the dividend yield (dividend divided by the stock price), and “g” is the expected sustainable growth rate.

[7] In the Schedules accompanying this testimony, the sample group companies are referred to by their stock ticker symbols, shown here in parentheses.

Q. WHAT GROWTH RATE (g) DID YOU ADOPT IN DEVELOPING YOUR DCF COST OF COMMON EQUITY FOR THE COMPANIES IN THIS PROCEEDING?

A. The growth rate variable in the traditional DCF model is quantified, theoretically, as the dividend growth rate investors expect to continue into the indefinite future. The DCF model is actually derived by 1) considering the dividend a growing perpetuity (*i.e.*, a payment to the stockholder that grows at a constant rate indefinitely) and 2) calculating the present value (the current stock price) of that perpetuity. The model also assumes that the company whose equity cost is to be measured exists in a steady state environment, *i.e.*, the payout ratio and the expected return are constant and the earnings, dividends, book value and stock price all grow at the same rate, forever.

While that assumption seems unrealistic because, in the short term, growth rates in those parameters (dividends, earnings and book value) can be quite different, over the long term it has proven to be true. For example, according to Value Line's published year-by-year retrospective of the Dow Jones Industrials Index (DJI) from 1920 through 2005, the average earnings, dividend and book value growth rates for the companies in the DJI were 5.3%, 4.9% and 5.2%, respectively.[8] For utility companies, over the long term, average growth rates in earnings, dividends and book value are even closer. Moody's *Public Utility Manual* reports that, between 1947 and 1999, average growth in earnings, dividend and book value growth of Moody's Electric Utilities was 3.34%, 3.22% and 3.66%, respectively.[9] Therefore, the fundamental DCF assumption that earnings, dividends and book value are expected to grow, over the long-term, at the same sustainable rate of growth is reasonable and is an accurate representation of how firms actually grow over time.

However, even though the long-term fundamental assumptions of the DCF have proven to be sound, as with all mathematical models of real-world phenomena, the DCF

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[8] www.valueline.com, Dow Jones Long Term Chart (PDF)

[9] Moody's ceased publication of its Public Utility Manual in 2001.

theory does not precisely "track" reality in the shorter term. Payout ratios and expected equity returns, as well as earnings and dividend growth rates, do change over the short term. Therefore, in order to properly apply the DCF model to any real-world situation and in this case, to find the long-term sustainable growth rate called for in the DCF theory, it is essential to understand the determinants of long-run expected dividend growth.

Q. CAN YOU PROVIDE AN EXAMPLE TO ILLUSTRATE THE DETERMINANTS OF LONG-RUN EXPECTED DIVIDEND GROWTH?

A. Yes, in Appendix B, I provide an example of the determinants of a sustainable growth rate on which to base a reliable DCF estimate. In addition, in Appendix B, I show how reliance on earnings growth rates alone, absent an examination of the underlying determinants of long-run dividend growth, can produce inaccurate DCF results.

Q. HOW HAVE YOU DEVELOPED AN ESTIMATE OF THE EXPECTED GROWTH RATE FOR THE DCF MODEL?

A. While I have calculated both the historical and projected sustainable growth rate for a sample of utility firms with similar-risk operations, I have not relied solely on that type of growth rate analysis. To estimate an appropriate DCF growth rate, I have also utilized published data regarding both historical and projected growth rates in earnings, dividends, and book value for the sample group of utility companies. Through an examination of all of those data, which are available to and used by investors, I estimate investors' long-term internal growth rate expectations. To that long-term growth rate estimate, I add any additional growth that is attributable to investors' expectations regarding the ongoing sale of stock for each of the companies under review.

Q. HOW HAVE YOU CALCULATED THE DCF GROWTH RATES FOR THE SAMPLE OF COMPARABLE COMPANIES?

A ~~Schedule~~ Exhibit_ (SGH-1), Schedule 4 pages 1 through 5, shows the retention ratios, equity returns, sustainable growth rates, book values per share and number of shares outstanding for the comparable electric companies for the past five years. Also included in the information presented in ~~Schedule~~ Exhibit_ (SGH-1), Schedule 44, are Value Line's projected 2011, 2012 and 2014-2016 values for equity return, retention ratio, book value growth rates and number of shares outstanding.

In evaluating these data, I first calculate the five-year average sustainable growth rate, which is the product of the earned return on equity (r) and the ratio of earnings retained within the firm (b). For example, ~~Schedule~~ Exhibit_ (SGH-1), Schedule 4, page 2, shows that the five-year average sustainable growth rate for one of the sample companies (American Electric Power; AEP) is 4.74%. The simple five-year average sustainable growth value is used as a benchmark against which I measure the company's most recent growth rate trends. Recent growth rate trends are more investor influencing than ~~are~~ simple historical averages. Continuing to focus on AEP as an example of the determination of a DCF growth rate, we see that sustainable growth has been relatively consistent throughout the historical period indicating stable growth. By the 2014—2016 period, Value Line projects AEP's sustainable growth will approximate the recent five-year average at 4.62%. These forward-looking data indicate that investors expect AEP to grow at a rate similar to the growth rate that has existed, on average, over the past five years.

At this point I should note that, while the five-year projections are given consideration in estimating a proper growth rate because they are available to and are used by investors, they are not given sole consideration. Without reviewing all the data available to investors, both projected and historic, sole reliance on projected information may be misleading. Value Line readily acknowledges to its subscribers the subjectivity necessarily presented in estimates of the future:

> "We have greater confidence in our year-ahead ranking

> system, which is based on proven price and earnings momentum, than in 3- to 5-year projections." (Value Line Investment Survey, Selection and Opinion, June 7, 1991, p.854).

Another factor to consider is that AEP's book value growth is expected to increase at a 5% level over the next five years. This information tends to confirm the sustainable growth projections and shows growth rate stability for this company. Also, as shown on ~~Schedule~~ Exhibit_ (SGH-1), Schedule 5, page 2, which contains published growth rate information for each company, AEP's dividend growth rate, which was ~~negative~~ 2% historically, is expected to increase to a 4% rate of growth. While this shows higher growth, the projected level is below sustainable growth projections.

Earnings growth rate data available from Value Line indicate that investors can expect a similar growth rate in the future (4.5%), compared to the sustainable growth rate projections. IBES and Zacks (investor advisory services that poll institutional analysts for growth earnings rate projections) also project moderate earnings growth rate for AEP—3.23% and 4.0%, respectively—over the next five years.

AEP's projected sustainable growth is expected to approach 4.6%, and dividends are expected to increase at a 4% annual rate. Per share earnings growth is expected to range from 3.23% to 4.5%. A long-term growth rate of 4.25% is a reasonable expectation for AEP.

Q. IS THE INTERNAL (b x r) GROWTH RATE THE FINAL GROWTH RATE YOU USE IN YOUR DCF ANALYSIS?

A. No. An investor's sustainable growth rate analysis does not end upon the determination of an internal growth rate from earnings retention. Investor expectations regarding growth from external sources (sales of stock) must also be considered and examined. For AEP, page 2 of ~~Schedule~~ Exhibit_ (SGH-1), Schedule 4 shows that the number of outstanding shares increased at a 4.93% rate over the most recent five-year period, due primarily to an equity issuance in 2009. Prior to 2009, AEP's shares outstanding grew at about a 1% rate. However, Value Line expects the number of shares outstanding to increase at a slower rate through the 2014—2016 period, bringing the share growth rate to a 0.79% rate by that time, due to a large issuance expected this year. An expectation of share growth of 1.75% is reasonable for this company.

Because AEP is currently trading at a market price that is 34% greater than book value, issuing additional shares will increase investors' growth rate expectations. Multiplying the expected growth rate in shares outstanding by (1 - (Book Value/Market Value))[10] increases the investor-expected growth rate for AEP by 0.45%. Therefore, the combined internal and external growth rate for AEP is 4.70% (4.25% internal growth and 0.45% external growth).

I have included the details of my growth rate analyses for AEP as an example of the methodology I use in determining the DCF growth rate for each company in the electric industry sample. A description of the growth rate analyses of each of the companies included in my sample groups is set out in Appendix D. ~~Schedule~~ Exhibit_ (SGH-1), Schedule 5, page 1, attached to this testimony shows the internal, external and resultant overall growth rates for the electric utility companies analyzed.

Q. HAVE YOU CHECKED THE REASONABLENESS OF YOUR GROWTH RATE ESTIMATES AGAINST OTHER PUBLICLY AVAILABLE, GROWTH RATE DATA?

A. Yes. Page 2 of ~~Schedule~~ Exhibit_ (SGH-1), Schedule 5, shows the results of my DCF growth rate analysis as well as five-year historic and projected earnings, dividends, and book value growth rates from Value Line; earnings growth rate projections from Reuters, the average of Value Line and IBES growth rates; and the five-year historical compound

[10] This is Gordon's formula for "v" the accretion rate related to new stock issues. B=book value, M=market value. (Gordon, M.J., The Cost of Capital to a Public Utility, MSU Public Utilities Studies, East Lansing, Michigan, 1974, pp. 30–33).

growth rates for earnings, dividends and book value for each company under study.

My average DCF growth rate estimate for all the electric utility companies included in my analysis is 5.00%. This figure is above Value Line's projected average growth rate in earnings, dividends, and book value for those same companies (4.81%) and is also approximately equal to the five-year historical average earnings, dividend, and book value growth rate reported by Value Line for those companies (5.06%). My growth rate estimate for the electric companies under review is below Value Line's earnings growth rate projections—6.15%—but above the average earnings projections of IBES and Zacks (4.09% and 4.39%, respectively). Also, my growth rate estimate is above the projected dividend growth rate of the sample companies, 4.04%.

Q. SOME ANALYSTS RELY SOLELY ON ANALYSTS' EARNINGS PROJECTIONS AS THE GROWTH RATE IN THE DCF; YOU HAVE NOT DONE SO. CAN YOU EXPLAIN WHY?

A. In my view, earnings growth rate projections are widely available and used by investors and therefore they deserve consideration in an informed, accurate assessment of the investor expected growth rate to be included in a DCF model. I do not believe, however, that projected earnings growth rates should be used as the *only* source of a DCF growth estimate. In other words, projected earnings growth rates are influential in, but not solely determinative of, investor expectations.

First, it is important to realize that, as I discuss in Appendix C, projected earnings growth rates may over- or understate the growth that can be sustained over time by the companies under review. This is important because long-term sustainable growth is required in an accurate DCF assessment of the cost of equity capital. The efficacy of projected earnings growth rates in any specific DCF analysis can only be determined through a study of the underlying fundamentals of growth—something that those who rely exclusively on analysts' earnings growth rate projections fail to do.

Second, the studies that support the use of analysts' earnings projections measure the ability of analysts' estimates to predict stock prices versus simple historical averages of other parameters. In that sort of simplistic comparison, analysts' projections perform better. However, I am aware of no cost of capital analyst that relies exclusively on historical average growth rates, nor is it reasonable to believe that any astute investor would do so. Therefore, while studies do indicate that analysts' earnings growth estimates are better indicators of stock prices than are simple historical averages of other growth rate parameters, those studies do not provide any basis for exclusive reliance on earnings growth projections in a DCF analysis.

Third, the sell-side institutional analysts that are polled by IBES and similar services offer relatively "rosy" expectations for the stock they follow—even when the analyst's actual expectations for the stock are not so sanguine. Simply put, some analysts overstate growth expectations to make the stocks they want to sell look more attractive. Although claims are often made that the opinions of sell-side analysts are not affected by the profits made by the other parts of the business that actually trade those securities, the "Cinderella effect" (analysts' overstating stock expectations) is not a new phenomenon, and is recognized in academia. As the authors of a widely-used finance textbook note regarding the use of projected earnings growth rates in a DCF analysis:

> Estimates of this kind are only as good as the long-term forecasts on which they are based. For example, several studies have observed that security analysts are subject to behavioral biases and their forecasts tend to be over-optimistic [footnote omitted]. If so, such DCF estimates of the cost of equity should be regarded as upper estimates of the true figure. [footnote omitted]. *See, for example,* A. Dugar and S. Nathan, "The Effect of Investment Banking Relationships on Financial Analysts' Earnings Investment Recommendations." (*Contemporary Accounting Research* 12 (1995), pp. 131-160.) (Brealey, Meyers, Allen, Principles of Corporate Finance, 8th Ed., McGraw-Hill Irwin, Boston, MA, (2006), p. 67)

As Chan and Lakonishok note in "The Level and Persistence of Growth Rates," published in the *Journal of Finance* (Vol. LVIII, No. 2, April 2003, p. 643), "[t]here is no persistence in long-term earnings growth beyond chance, and there is low predictability even with a wide variety of predictor variables. Specifically, IBES growth forecasts are overly optimistic and add little predictive power." This concern regarding investors' use of analysts' growth estimates is also underscored by an investor's service sponsored by the *Wall Street Journal*:

> "You should be careful when looking at analyst recommendations for several reasons. First of all, many analysts suffer from a conflict of interest between the firm that employs them and the company whose stock they track. Oftentimes, an analyst will be responsible for issuing reports on a company that is a current or potential client of their employer (usually an investment bank). Since they know that their employer would like to keep the client's business, the analyst may be tempted to issue a rosier outlook for the stock than what it really deserves." (Investorguide.com, "University," Analysts and Earnings Estimates, www.investorguide.com/igustockanalyst.html)

Fourth, much of the academic work touted as support for reliance on earnings growth is based on data from the IBES database (now owned by Thomson); however, academic research recently published in the *Journal of Finance* indicates that there have been nonrandom, systematic errors in that database, which call into question the reliability of research (such as the research on the reliability of analysts' earnings estimates) based on those data. The researchers document that the historical contents of the IBES data base have been "quite unstable over time" and state:

> Data are the bedrock of empirical research in finance. When there are questions about the accuracy or completeness of a data source, researchers routinely go to great lengths to investigate measurement error, selection bias, or reliability. But what if the very contents of a

> historical database were to change, in error, over time? Such changes to the historical record would have important implications for empirical research. They could undermine the principle of replicability, which in the absence of controlled experiments is the foundation of empirical research in finance. They could result in over- or underestimates of the magnitude of empirical effects, leading researchers down blind alleys. Also to the extent that financial-market participants use academic research for trading purposes, they could lead to resource allocation. … We document that the historical contents of the I/B/E/S recommendations database have been quite unstable over time. (Lungqvist, Malloy, Marston, "Rewriting History," *The Journal of Finance*, Vol. 64, No. 4, August 2009, pp. 1935-1960)

Fifth, widely-used investor services such as Value Line publish three- to fie-year dividend and book value growth rate projections for each company it follows. Investors have equal access to all three growth rates (earnings, dividends and book value) and, it would be reasonable to assume, utilize all three when making a determination of long-term sustainable growth. Also, the Efficient Market Hypothesis (a fundamental tenet of modern finance) holds that all published material is considered by investors and is, therefore, included in stock prices, indicating that to properly evaluate the cost of capital, other growth rates besides earnings should be considered. Moreover, as noted previously, the DCF model assumes that earnings, dividends and book value all grow at the same rate. Therefore, the use of the average of those three projected growth rate parameters published in Value Line would provide a more balanced growth rate analysis than an earnings growth-only DCF model.

Q. DOES THIS CONCLUDE THE GROWTH RATE PORTION OF YOUR DCF ANALYSIS?

A. Yes, it does.

Q. HOW HAVE YOU CALCULATED THE DIVIDEND YIELDS?

A. I have estimated the next quarterly dividend payment of each firm analyzed and annualized them for use in determining the dividend yield. If the quarterly dividend of any company was expected to be raised in the next quarter (1st or 2nd quarter 2012), I increased the current quarterly dividend by (1+g). Because some of the sample companies had recently increased dividends or were not expected to increase dividends at all during 2012, for the utility companies in the sample groups, a dividend adjustment was necessary only for TECO, ALLETE, Westar, Avista and UniSource.

The nest quarter annualized dividends were divided by a recent daily closing average stock price to obtain the DCF dividend yields. I use the most recent six-week period to determine an average stock price in a DCF cost of equity determination because I believe that period of time is long enough to avoid daily fluctuations and recent enough so that the stock price captured during the study period is representative of current investor expectations.

~~Schedule~~ Exhibit_ (SGH-1), Schedule 6 contains the market prices, annualized dividends and dividend yields of the utility companies under study. ~~Schedule~~ Exhibit_ (SGH-1), Schedule 6 indicates that the average dividend yield for the sample group of electric companies is 4.55%. The year-ahead dividend yield projection published by Value Line for the electric utility sample group is 4.59% (Value Line, *Summary & Index*, February 3, 2012). By that measure, my dividend yield calculation is representative of investor year-ahead expectations.

Q. WHAT IS YOUR COST OF EQUITY CAPITAL ESTIMATE FOR THE ELECTRIC UTILITY COMPANIES, UTILIZING THE DCF MODEL?

A. ~~Schedule~~ Exhibit_ (SGH-1), Schedule 7 shows that the average DCF cost of equity capital for the group of electric utilities is 9.55%.

C. CAPITAL ASSET PRICING MODEL

Q. PLEASE DESCRIBE THE CAPITAL ASSET PRICING MODEL (CAPM) YOU USED TO ARRIVE AT AN ESTIMATE FOR THE COST RATE OF KPCO'S EQUITY CAPITAL.

A. The CAPM states that the expected rate of return on a security is determined by a risk-free rate of return plus a risk premium, which is proportional to the non-diversifiable (systematic) risk of a security. Systematic risk refers to the risk associated with movements in the macro-economy (the economic "system") and, thus, cannot be eliminated through diversification by holding a portfolio of securities. The beta coefficient (β) is a statistical measure that attempts to quantify the non-diversifiable risk of the return on a particular security against the returns inherent in general stock market fluctuations. The formula is expressed as follows:

$$k = r_f + \beta(r_m - r_f), \qquad (2)$$

where "k" is the cost of equity capital of an individual security, "r_f" is the risk-free rate of return, "β" is the beta coefficient, "r_m" is the average market return and "$r_m - r_f$" is the market risk premium. The CAPM is used in my analysis not as a primary cost of equity analysis, but as a check of the DCF cost of equity estimate. Although I believe the CAPM can be useful in testing the reasonableness of a cost of capital estimate, certain theoretical shortcomings of this model (when applied in cost of capital analysis) reduce its usefulness.

Q. CAN YOU EXPLAIN WHY THE CAPM ANALYSIS SHOULD BE APPLIED TO COST OF CAPITAL ESTIMATION WITH CAUTION?

A. Yes. The reasons why the CAPM should be used in cost of capital analysis with caution are set out below. It is important to understand that my caution with regard to the use of the CAPM in a cost of equity capital analysis does not indicate that the model is not a useful description of the capital markets or that it is not widely used, because it is. Rather, my caution recognizes that in the practical application of the CAPM to cost of capital analysis there are problems that can cause the results of that type of analysis to be less reliable than other, more widely accepted models, such as the DCF.

There has been much comment in the financial literature regarding the strength of the assumptions that underlie the CAPM and the inability to substantiate those assumptions through empirical analysis. Also, there are problems with the key CAPM risk measure—beta—that indicate that the CAPM analysis is not a reliable primary indicator of equity capital costs.

Cost of capital analysis is a decidedly forward-looking, or *ex-ante*, concept. Beta is not. The measurement of beta is derived with historical, or *ex-post*, information. Therefore, the beta of a particular company, because it is usually derived with five years of historical data in order to bolster statistical reliability, is slow to change to current (*i.e.*, forward-looking) conditions, and some price abnormality that may have happened four years ago could substantially affect beta while currently being of little actual concern to investors.

In addition, there are substantial differences of opinion with regard to the magnitude of the investor-expected market risk premium (the expected return difference between stocks and Treasury bonds). Those differences of opinion obtain from different historical averaging methods (*i.e.*, arithmetic versus geometric) as well as from the use of different time periods over which to measure the return differences between stocks and bonds.

Q. WHAT VALUE HAVE YOU CHOSEN FOR A RISK-FREE RATE OF RETURN IN YOUR CAPM ANALYSIS?

A. As the CAPM is designed, the risk-free rate is that rate of return investors can realize with certainty. The nearest analog in the investment spectrum is the 13-week U. S. Treasury Bill. However, T-Bills can be heavily influenced by Federal Reserve policy, as they have been over the past three years. While longer-term Treasury bonds have equivalent default risk to T-Bills, those longer-term government securities carry maturity risk that the T-Bills do not have. When investors tie up their money for longer periods of time, as they do when purchasing a long-term Treasury Bond, they must be compensated for future investment opportunities forgone as well as the potential for future changes in inflation. Investors are compensated for this increased investment risk by receiving a higher yield on T-Bonds. When T-Bills and T-Bonds exhibit a "normal" (historical average) spread of about 1.5% to 2%, the results of a CAPM analysis that matches a higher market risk premium with lower T-Bill yields or a lower market risk premium with higher T-Bond yields are very similar.

As I noted in my previous discussion of the macro-economy, in an attempt to fend off a recession and inject liquidity into the financial system, the Fed has acted vigorously since the financial crisis to lower short-term interest rates. Over the most recent six-week period, T-Bills have produced an average yield of only 0.02%. During that time period Treasury Bonds have been priced to yield 3.00% (data from Value Line *Selection & Opinion*, six most recent weekly editions (12/30/11 through 2/3/12)). However, as I noted in Section II, in my discussion of the current economic environment, the current yield for T-Bonds is influenced by an increased demand for secure investments (a flight to quality), and, absent that exaggerated demand, the long-term trend of T-Bond pricing would indicate a current yield of approximately 4%. Therefore, for purposes of a forward-looking CAPM analysis in this proceeding I will use 4.00% as the long-term risk-free rate.

Q. DO YOU BELIEVE THE USE OF A LONG-TERM TREASURY BOND RATE IS APPROPRIATE IN THE CAPM?

A. In the current economic environment, with short-term Treasury Bills yielding a near zero return, the use of a long-term Treasury bond would provide a more accurate indication of the risk-free return investors require and produces a more accurate estimate of investors' cost of equity. Therefore, in this testimony, I will present the CAPM cost of equity results using only long-term Treasury bond yields. With that measure of the risk-free rate, I use the corresponding measure of the market risk premium (*i.e.*, those based on the difference between stock returns and long-term Treasury bond returns).

Q. WHAT MARKET RISK PREMIUM HAVE YOU USED IN YOUR CAPM ANALYSIS?

A. The market risk premium is the difference between the return investors expect on stocks and the return they expect on a risk-free rate of return such as a U.S. Treasury bond. The "traditional" view, supported primarily by the earned return data over the past 80 years published by Morningstar (formerly Ibbotson Associates), is based on the historical difference between the returns on stocks and the returns on bonds. That view assumes that the returns actually earned by investors over a long period of time are representative of the returns they expect to earn in the future.

For example, the current Morningstar data show that investors have earned a return of 11.8% on stocks and 5.8% on long-term Treasury bonds since 1926.[11] Therefore, based on those historical data, it is assumed that investors will require a risk premium in the future of 6.0% above the long-term risk-free rate to invest in stocks [11.8% - 5.8% = 6.0%]. With a current long-term T-Bond yield of approximately 4.00%, that assumption indicates an investor expectation of a 10.00% return for the stock market in general [4.00% + 6.0% = 10.00%]. However, current research indicates that there are

[11] Ibbotson SBBI 2010 Valuation Yearbook, p. 23.

aspects of the Morningstar historical data set that, when examined, point not only to lower historical risk premiums than those reported by Morningstar, but also lower expected risk premiums. ~~that are also lower.~~

Q. HAS THE RESEARCH YOU MENTION FOUND ITS WAY INTO TODAY'S FINANCE TEXTBOOKS?

A. Yes. In the 2006 edition of their widely used finance textbook, Brealey and Meyers discuss the findings of many different recent studies regarding the market risk premium.[12] Importantly, in prior editions of their textbooks Brealey et al. cited the Morningstar historical data; now they do not. Instead they cite the risk premium work of Dimson, Staunton and Marsh, authors of *Triumph of the Optimists*, in which they review a longer-term data set than that used by Morningstar and conclude that market risk premiums expected in the future are below historical averages.[13]

The textbook authors conclude, based on a review of the recent evidence regarding the market risk premium, that a reasonable range of arithmetic equity premiums above *short-term* Treasury Bills is 5% to 8%.[14]

Because the long-term historical difference in the return between T-Bonds and T-Bills has been approximately 1.2%, Brealey and Meyers' textbook indicates a long-term market risk premium relative to T-Bonds ranging from 3.8% to 6.8% [5% - 1.2% = 3.8%; 8% - 1.2% = 6.8%].[15] The mid-point of that 3.8% to 6.8% reasonable risk premium range is 5.3%. Although 5.3% is higher than other risk premium estimates, that average market risk premium added to a current T-Bond yield of 4.00%, indicates a current equity return expectation for U.S. equities of 9.3%. Because utility stocks are less risky than the

[12] Brealey, R., Meyers, S., Allen, F., *Principles of Corporate Finance*, 8th Edition, McGraw-Hill, Irwin, Boston MA, 2006.

[13] Dimson, E., Staunton, M., March, P., *Triumph of the Optimists: 101 Years of Global Investment Returns*, Princeton University Press, Princeton, NJ, 2002.

[14] Op cit, p. 154.

[15] Op cit, pp. 149, 222.

market as a whole, an appropriate return on equity for utilities would, therefore, be lower, according to CAPM theory.

Q. WHAT HAVE YOU CHOSEN AS THE MARKET RISK PREMIUM FOR THE CAPM ANALYSIS?

A. In its~~their~~ 2010 edition of *Stocks, Bonds, Bills and Inflation*, Ibbotson Associates indicates that the average market risk premium between stocks and T-Bonds over the 1926–2009 time period is 6.0% (based on an arithmetic average) and 4.4% (based on a geometric average). I have, in prior testimony, used these long-term historical average values as estimates of the market risk premium in the CAPM analysis.

As I have noted above, recent research in the field of financial economics has shown that the market risk premium data published by Morningstar is likely to overstate investor-expected market risk premiums. Current finance textbooks (Brealey and Meyers) indicate that the long-term arithmetic average market risk premium ranges from 3.8% to 6.8%. The midpoint of Brealey and Meyer's long-term risk premium range is 5.3%, which falls within the 4.4% to 6.0% range published by Morningstar. For purposes of determining the CAPM cost of equity in this proceeding I will use the mid-point of the long-term risk premium range set out in the most recent Brealey and Meyer's text—5.3%—as well as the published Morningstar market risk premiums to develop a range of CAPM equity cost estimates.

Q. WHAT VALUES HAVE YOU CHOSEN FOR THE BETA COEFFICIENTS IN THE CAPM ANALYSIS?

A. Value Line reports beta coefficients for all the stocks it follows. Value Line's beta is derived from a regression analysis between weekly percentage changes in the market price of a stock and weekly percentage changes in the New York Stock Exchange Composite Index over a period of five years. The average beta coefficient of the sample of electric companies is 0.72.

Q. WHAT IS YOUR RECOMMENDED COST OF EQUITY CAPITAL FOR THE SAMPLE OF ELECTRIC COMPANIES USING THE CAPITAL ASSET PRICING MODEL ANALYSIS?

A. ~~Schedule~~ Exhibit_ (SGH-1), Schedule 8 shows that the average Value Line beta coefficient for the group of electric companies under study is 0.72. The upper end of the range of market risk premiums published by Ibbotson of 6.0% would, upon the adoption of a 0.72 beta, become a sample group premium of 4.31% (0.72 x 6.0%). That nonspecific risk premium added to the risk-free T-Bond rate of 4.00%, previously derived, yields a common equity cost rate estimate of 8.32%. Using the geometric long-term market risk premiums published by Morningstar (4.4%) and the mid-point of the Brealey and Meyer's range (5.3%) the resulting CAPM equity cost estimates range from 7.16% to 7.81%. This analysis, even at the high end (8.32%) indicates a cost of equity capital well below the standard DCF analysis.

D. MODIFIED EARNINGS-PRICE RATIO ANALYSIS

Q. PLEASE DESCRIBE THE MODIFIED EARNINGS-PRICE RATIO (MEPR) ANALYSIS OF THE COST OF COMMON EQUITY CAPITAL.

A. The earnings-price ratio is the expected earnings per share divided by the current market price. In cost of capital analysis, the earnings-price ratio (which is one portion of this analysis) can be useful in a corroborative sense, since it can be a good indicator of the proper range of equity costs when the market price of a stock is near its book value. When the market price of a stock is *above* its book value, the earnings-price ratio *understates* the cost of equity capital. ~~Schedule~~ Exhibit_ (SGH-1), Schedule 9 contains mathematical proof for this concept. The opposite is also true, *i.e.*, the earnings-price ratio *overstates* the cost of equity capital when the market price of a stock is *below* book value.

Under current market conditions, the utilities under study have an average market-to-book ratio of 1.42, and, therefore, the average earnings-price ratio alone will understate the cost of equity for the sample groups. However, I do not use the earnings-price ratio alone as an indicator of equity capital cost rates. Because of the relationship among the earnings-price ratio, the market-to-book ratio and the investor-expected return on equity described mathematically in ~~Schedule~~ Exhibit_ (SGH-1), Schedule 9, I have modified the earnings-price ratio analysis by including expected returns on equity for the companies under study. It is that modified analysis that I will use to assist in estimating an appropriate range of equity capital costs in this proceeding.

Q. PLEASE EXPLAIN THE RELATIONSHIP AMONG THE EARNINGS-PRICE RATIO, THE EXPECTED RETURN ON EQUITY, AND THE MARKET-TO-BOOK RATIO.

A. When the expected return on equity (ROE) approximates the cost of equity, the market price of the utility approximates its book value and the earnings-price ratio provides an accurate estimate of the cost of equity. As the investor-expected return on equity for a utility begins to exceed the investor-required return (the cost of equity capital), the market price of the firm will tend to exceed its book value. As explained above, when the market price exceeds book value, the earnings-price ratio understates the cost of equity capital. Therefore, when the expected equity return exceeds the cost of equity capital, the earnings-price ratio will understate that cost rate.

Also, in situations where the expected equity return is below what investors require for that type of investment, market prices fall below book value. Further, when market-to-book ratios are below 1.0, the earnings-price ratio overstates the cost of equity capital. Thus, the expected rate of return on equity and the earnings-price ratio tend to move in a countervailing fashion around the cost of equity capital.

When market-to-book ratios are above one, the expected equity return exceeds and the earnings-price ratio understates the cost of equity capital. When market-to-book ratios are below one, the expected equity return understates and the earnings-price ratio exceeds the cost of equity capital. Further, as market-to-book ratios approach unity, the expected return and the earnings-price ratio approach the cost of equity capital. Therefore, the average of the expected book return and the earnings-price ratio provides a reasonable estimate of the cost of equity capital.

These relationships represent general rather than precisely quantifiable tendencies but are useful in corroborating other cost of capital methodologies. The Federal Energy Regulatory Commission, in its generic rate of return hearings, found this technique useful and indicated that under the circumstances of market-to-book ratios exceeding unity, the cost of equity is bounded above by the expected equity return and below by the earnings-price ratio (*e.g.*, 50 *Fed Reg*, 1985, p. 21822; 51 *Fed Reg*, 1986, pp. 361, 362; 37 FERC ¶ 61,287). The midpoint of these two parameters, therefore, produces an estimate of the cost of equity capital which, when market-to-book ratios are different from unity, is far more accurate than the earnings-price ratio alone.

Q. IS THERE OTHER THEORETICAL SUPPORT FOR THE USE OF AN EARNINGS-PRICE RATIO IN CONJUNCTION WITH AN EXPECTED RETURN ON EQUITY AS AN INDICATOR OF THE COST OF EQUITY CAPITAL?

A. Elton and Gruber, *Modern Portfolio Theory and Investment Analysis* (New York University, Wiley & Sons, New York, 1995, pp. 401-404) provide support for reliance on my modified earnings-price ratio analysis.

The Elton and Gruber posit the following formula,

$$k = (1\text{-}b)E/(1\text{-}cb)P, \qquad (3)$$

where "k" is the cost of equity capital, "b" is the retention ratio, "E" is earnings, "P" is market price and "c" is the ratio of the expected return on equity to the cost of equity capital (ROE/k). This formula shows that when ROE = k, "c" equals 1.0 and the cost of equity capital equals the earnings-price ratio. Moreover, in that case, ROE is greater than "k" (as it is in today's market), "c" is greater than 1.0, and the earnings-price ratio will understate the cost of equity. Also, the more that ROE exceeds "k" the more the earnings price ratio will understate "k." In other words, as I note in my Direct Testimony those two parameters, the earnings-price ratio and the expected return on equity (ROE) orbit around the cost of equity capital, with the cost of equity as the locus, and fluctuate so that their mid-point approximates the cost of equity capital.

Assuming an industry average retention ratio of about 30% (*i.e.*, 70% of earnings are paid out as dividends), the stochastic relationship between the expected return (ROE) and the earnings price ratio can be determined from Equation (3), above, as shown in Table I below. Most importantly, Equation (3) shows that the average of the EPR and ROE (which is my MEPR analysis) will approximate "k", the cost of equity capital.

Table I.

SUPPORT FOR THE MODIFIED EARNINGS PRICE RAITO ANALYSIS

Cost of Equity	Retention Ratio	ROE	ROE/k	Earnings Price Ratio	M.E.P.R. (ROE+EPR)/2
[1]	[2]	[3]	[4]=[3]/[1]	[5]	[6]=([3]+[5])/2
10.00%	35.00%	13.00%	1.3	8.38%	10.69%
10.00%	35.00%	12.00%	1.2	8.92%	10.46%
10.00%	35.00%	11.00%	1.1	9.46%	10.23%
10.00%	35.00%	10.00%	1.0	10.00%	10.00%
10.00%	35.00%	9.00%	0.9	10.54%	9.77%
10.00%	35.00%	8.00%	0.8	11.08%	9.54%
10.00%	35.00%	7.00%	0.7	11.62%	9.31%

[5] From Equation (3): E/P = k(1-cb)/(1-b)

As the data in Table I shows, the average of the expected return (ROE) and the earnings price ratio (EPR) produces an estimate of the cost of common equity capital of sufficient accuracy to serve as a check of other analyses, which is how I use the model in my testimony.

Q. WHAT ARE THE RESULTS OF YOUR EARNINGS-PRICE RATIO ANALYSIS OF THE COST OF EQUITY FOR THE SAMPLE GROUP?

A. ~~Schedule~~ Exhibit__ (SGH-1), Schedule 10 shows the Zacks projected 2012 per share earnings for each of the firms in the sample group. Recent average market prices (the same market prices used in my DCF analysis), and Value Line's projected return on equity for 2012 and 2014—2016 for each of the companies are also shown.

The average earnings-price ratio for the electric sample group, 7.23%, is below the cost of equity for those companies due to the fact that their average market-to-book ratio is currently above unity (average electric utility M/B = 1.42). The sample electric Company's 2012 expected book (accounting) equity return averages 9.85%. For the electric sample group, then, the midpoint of the earnings-price ratio and the current equity return is 8.54%.

~~Schedule~~ Exhibit_ (SGH-1), Schedule 10, also shows that the average expected book equity return for the electric utilities over the next three- to five-year period increases slightly to 10.38%. The midpoint of the longer-term projected return on book equity (10.38%) and the current earnings-price ratio (7.23%) is 8.81%. That longer-term analysis provides another forward-looking estimate of the equity capital cost rate of electric utility firms. The results of this MEPR analysis also indicate that the DCF equity cost estimate, previously derived, may be overstated.

E. MARKET-TO-BOOK RATIO ANALYSIS

Q. PLEASE DESCRIBE YOUR MARKET-TO-BOOK (MTB) ANALYSIS OF THE COST OF COMMON EQUITY CAPITAL FOR THE SAMPLE GROUPS.

A. This technique of analysis is a derivative of the DCF model that attempts to adjust the capital cost derived with regard to inequalities that might exist in the market-to-book ratio. This method is derived algebraically from the DCF model and, therefore, cannot be considered a strictly independent check of that method. However, the MTB analysis is useful in a corroborative sense. The MTB seeks to determine the cost of equity using market-determined parameters in a format different from that employed in the DCF analysis. In the DCF analysis, the available data is "smoothed" to identify investors' long-term sustainable expectations. The MTB analysis, while based on the DCF theory, relies instead on point-in-time data projected one year and five years into the future and, thus, offers a practical corroborative check on the traditional DCF. The MTB formula is derived as follows:

Solving for "P" from Equation (1), the standard DCF model, we have

$$P = D/(k-g). \qquad (4)$$

But the dividend (D) is equal to the earnings (E) times the earnings payout ratio, or one minus the retention ratio (b), or

$$D = E(1-b). \qquad (5)$$

Substituting Equation (5) into Equation (4), we have

$$P = \frac{E(1-b)}{k-g}\ . \qquad (6)$$

The earnings (E) are equal to the return on equity (r) times the book value of that equity (B). Making that substitution into Equation (4), we have

$$P = \frac{rB(1-b)}{k-g}\ . \qquad (7)$$

Dividing both sides of Equation (7) by the book value (B) and noting from Equation (ii~~i~~) in Appendix C that g = br+sv,

$$\frac{P}{B} = \frac{r(1-b)}{k-br-sv}\ . \qquad (8)$$

Finally, solving Equation (8) for the cost of equity capital (k) yields the MTB formula:

$$k = \frac{r(1-b)}{P/B} + br+sv. \qquad (9)$$

Equation (9) indicates that the cost of equity capital equals the expected return on equity multiplied by the payout ratio, divided by the market-to-book ratio plus growth. ~~Schedule~~ Exhibit_ (SGH-1), Schedule 11 shows the results of applying Equation (9) to the defined parameters for the electric utility firms in the comparable sample. For the electric utility sample group, page 1 of ~~Schedule~~ Schedule 11 utilizes current year (2012) data for the MTB analysis while page 2 utilizes Value Line's longer-term, 2014-2016 projections.

The MTB cost of equity for the sample of electric utility firms, recognizing a current average market-to-book ratio of 1.42, is 9.32% using the current year projections and 9.33% using projected three- to five-year data. Those point-in-time estimates are slightly below my DCF equity cost estimate.

F. SUMMARY

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR EQUITY CAPITAL COST ANALYSES FOR THE SAMPLE GROUP OF ELECTRIC UTILITY COMPANIES SIMILAR IN RISK TO KPCO.

A. My analysis of the cost of common equity capital for the sample group of integrated electric utility companies is summarized in the table below.

Table II.

Equity Cost Estimates

METHOD	Electric Utility Companies
DCF	9.55%
CAPM	7.81%/8.32%
MEPR	8.54%/8.81%
MTB	9.32%/9.35%

For the electric utility sample group, the DCF results are 9.55%. In addition, the corroborating cost of equity analyses (MEPR, MTB, and CAPM), indicate that the traditional DCF result may be overstated. Averaging the lowest and highest results of all the corroborative analyses for the electric companies produces an equity cost range of 8.56% to 8.82%, with a midpoint of 8.69%, 86 basis points below the DCF result OF 9.55%. Therefore, weighing all the evidence presented herein (including the consideration that the next interest rate move by the Federal Reserve will probably be upward), my best estimate of the cost of equity capital for a companies like KPCO, facing similar risks as this group of electric utilities, ranges from 9.00% to 9.75%, with a mid-point of 9.375%.

However, the Company's operating risk under the environmental surcharge is less than that under traditional regulation due, primarily, to the very short time between expenditure of capital and recovery from ratepayers. Therefore, a reasonable estimate of the current cost of equity capital for KPCO would be in the lower portion of a reasonable range of otherwise similar-risk companies, or in this instance 9.0% to 9.375%. The mid-point of the lower portion of a reasonable range would be 9.1875%, rounded to 9.20%. Therefore, if the Commission elects to use the overall cost of capital to determine the rate of return recovered on KPCO's environmental plant investment, I recommend the use of an equity return that recognizes the lower risk of Kentucky's environmental surcharge mechanism, 9.20%.

Q. IS AN EXPLICIT FLOTATION COST ALLOWANCE NECESSARY IN ORDER FOR THE COMPANY TO BE ABLE TO RAISE EQUITY CAPITAL IN THE FINANCIAL MARKETS?

A. No. An explicit adjustment to the allowed return on common equity for flotation costs is unwarranted.

First, it is often stated that stock flotation costs are like those associated with bonds and, because the costs of issuance are included in the embedded cost rate of debt, similar costs should be included in the cost of common equity. However, that concept is inapt because bonds have a fixed (contractual) cost and common stock does not. Moreover, even if it were true, the current relationship between the electric utility sample group's stock price and its book value would indicate the need for a flotation cost *reduction* to the market-based cost of equity, not an increase.

For example, when a bond is issued at a price that exceeds its face (book) value, and that difference between market price and book value is greater than the costs incurred during the issuance, the embedded cost of that debt (the cost to the company) is *lower* than the coupon rate of that debt.

In the current economic environment for the electric utility common stocks studied to determine the cost of equity in this proceeding, those stocks are selling at a market price 42% above book value. (See ~~Schedule~~ Exhibit_ (SGH-1), Schedule 5, p. 1) The difference between the market price of electric utility stock and book value is larger than any issuance expense the companies might incur. If common equity flotation costs were considered to be like the flotation costs of bonds and if an explicit adjustment to the cost of common equity were, therefore necessary, then the adjustment should be downward, not upward.

Second, flotation cost adjustments are often predicated on the prevention of the dilution of stockholder investment. However, the reduction of the book value of stockholder investment due to issuance expenses can occur only when the utility's stock is selling at a market price at or below its book value. As noted, the companies under review are selling at a substantial premium to book value. Therefore, every time a new share of that stock is sold, existing shareholders realize an *increase* in the per share book value of their investment. No dilution occurs, even without any explicit flotation cost allowance.

Third, the vast majority of the issuance expenses incurred in any public stock offering are "underwriter's fees" or "discounts." Underwriter's fees/discounts are not out-of-pocket expenses for the issuing company. On a per-share basis, they represent only the difference between the price the underwriter receives from the public and the price the utility receives from the underwriter for its stock. As a result, underwriter's fees are not an expense incurred by the issuing utility and recovery of such "costs" should not be included in rates.

In addition, the amount of the underwriter's fees are prominently displayed on the front page of every stock offering prospectus and, as a result, the investors who participate in those offerings (*e.g.*, brokerage firms) are quite aware that a portion of the price they pay does not go to the company but goes, instead, to the underwriters. By electing to buy the stock with that understanding, those investors have effectively accounted for those issuance costs in their risk-return framework by paying the offering price. Therefore, they do not need any additional adjustments to the allowed return of the regulated firm to "account" for those costs.

Fourth, research has shown that a specific adjustment for issuance expenses is unnecessary.[16] There are other transaction costs which, when properly considered, eliminate the need for an explicit issuance expense adjustment to equity capital costs. The transaction cost that is improperly ignored by the advocates of issuance expense adjustments is brokerage fees. Issuance expenses occur with an initial issue of stock in a primary market offering. Brokerage fees occur in the much larger secondary market where pre-existing shares are traded daily. Brokerage fees tend to increase the price of the stock to the investor to levels above that reported in the *Wall Street Journal*; i.e., the market price analysts use in a DCF analysis. Therefore, if brokerage fees were included in a DCF cost of capital estimate they would raise the effective market price, lower the dividend yield and lower the investors' required return. Under a symmetrical treatment, if

[16] "A Note on Transaction Costs and the Cost of Common Equity for a Public Utility," Habr, D., *National Regulatory Research Institute Quarterly Bulletin*, January 1988, pp. 95-103.

transaction costs that, supposedly, raise the required return (issuance expenses) are included, then those costs that lower the required return (brokerage fees) should also be included. As shown by the research noted above, those transaction costs essentially offset each other and no specific equity capital cost adjustment is warranted.

An explicit increase to the market-based cost of equity for flotation costs is unnecessary.

Q. WHAT OVERALL COST OF CAPITAL FOR KPCO'S UTILITY OPERATIONS RESULTS FROM THE APPLICATION OF AN ALLOWED EQUITY RETURN OF 9.2%?

A. As shown on Schedule 11, allowing an equity return of 9.2%, would produce an overall cost of capital of 6.99% for Kentucky Utilities using the Company's requested capital structure and embedded cost rates. In addition, Schedule 12 shows that a 9.2% return on equity allows the Companies the opportunity to earn a pre-tax return on common equity that is 2.87 greater than its interest costs. As previously noted, this level of interest coverage exceeds that realized by KPCO over the past three years and, therefore, provides the Company an opportunity to support its financial position, as required by *Hope* and *Bluefield*.

Q. DOES THIS CONCLUDE YOUR ANALYSIS OF THE COST OF EQUITY CAPITAL, MR. HILL?

A. Yes, it does.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY, MR. HILL?

A. Yes, it does.

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Appendix A to the
Proxy Statement

American Electric Power

2010 Annual Report

Audited Consolidated Financial Statements and
Management's Financial Discussion and Analysis

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CONTENTS

AMERICAN ELECTRIC POWER
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GLOSSARY OF TERMS

When the following terms and abbreviations appear in the text of this report, they have the meanings indicated below.

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP or Parent	American Electric Power Company, Inc.
AEP Consolidated	AEP and its majority owned consolidated subsidiaries and consolidated affiliates.
AEP Credit	AEP Credit, Inc., a subsidiary of AEP which factors accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP East companies	APCo, CSPCo, I&M, KPCo and OPCo.
AEP Foundation	AEP charitable organization created in 2005 for charitable contributions in the communities in which AEP's subsidiaries operate.
AEP Power Pool	Members are APCo, CSPCo, I&M, KPCo and OPCo. The Pool shares the generation, cost of generation and resultant wholesale off-system sales of the member companies.
AEP System or the System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEP West companies	PSO, SWEPCo, TCC and TNC.
AEPEP	AEP Energy Partners, Inc., a subsidiary of AEP dedicated to wholesale marketing and trading, asset management and commercial and industrial sales in the deregulated Texas market.
AEPES	AEP Energy Services, Inc., a subsidiary of AEP Resources, Inc.
AEPSC	American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries.
AFUDC	Allowance for Funds Used During Construction.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
APSC	Arkansas Public Service Commission.
ASU	Accounting Standard Update.
CAA	Clean Air Act.
CLECO	Cleco Corporation, a nonaffiliated utility company.
CO_2	Carbon Dioxide and other greenhouse gases.
Cook Plant	Donald C. Cook Nuclear Plant, a two-unit, 2,191 MW nuclear plant owned by I&M.
CSPCo	Columbus Southern Power Company, an AEP electric utility subsidiary.
CSW	Central and South West Corporation, a subsidiary of AEP (Effective January 21, 2003, the legal name of Central and South West Corporation was changed to AEP Utilities, Inc.).
CSW Operating Agreement	Agreement, dated January 1, 1997, as amended, by and among PSO and SWEPCo governing generating capacity allocation, energy pricing, and revenues and costs of third party sales. AEPSC acts as the agent.
CTC	Competition Transition Charge.
CWIP	Construction Work in Progress.
DCC Fuel	DCC Fuel LLC, DCC Fuel II LLC and DCC Fuel III LLC consolidated variable interest entities formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M.
DETM	Duke Energy Trading and Marketing L.L.C., a risk management counterparty.
DHLC	Dolet Hills Lignite Company, LLC, a wholly-owned lignite mining subsidiary of SWEPCo.
E&R	Environmental compliance and transmission and distribution system reliability.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company.
ERCOT	Electric Reliability Council of Texas.
ERISA	Employee Retirement Income Security Act of 1974, as amended.
ESP	Electric Security Plans, filed with the PUCO, pursuant to the Ohio Amendments.

Term	Meaning
ETA	Electric Transmission America, LLC an equity interest joint venture with MidAmerican Energy Holdings Company formed to own and operate electric transmission facilities in North America outside of ERCOT.
ETT	Electric Transmission Texas, LLC, an equity interest joint venture between AEP Utilities, Inc. and MidAmerican Energy Holdings Company Texas Transco, LLC formed to own and operate electric transmission facilities in ERCOT.
FAC	Fuel Adjustment Clause.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FGD	Flue Gas Desulfurization or Scrubbers.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
GAAP	Accounting Principles Generally Accepted in the United States of America.
IGCC	Integrated Gasification Combined Cycle, technology that turns coal into a cleaner-burning gas.
Interconnection Agreement	Agreement, dated July 6, 1951, as amended, by and among APCo, CSPCo, I&M, KPCo and OPCo, defining the sharing of costs and benefits associated with their respective generating plants.
IRS	Internal Revenue Service.
IURC	Indiana Utility Regulatory Commission.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
JMG	JMG Funding LP.
KGPCo	Kingsport Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
kV	Kilovolt.
KWH	Kilowatthour.
LPSC	Louisiana Public Service Commission.
MISO	Midwest Independent Transmission System Operator.
MLR	Member load ratio, the method used to allocate AEP Power Pool transactions to its members.
MMBtu	Million British Thermal Units.
MPSC	Michigan Public Service Commission.
MTM	Mark-to-Market.
MW	Megawatt.
NEIL	Nuclear Electric Insurance Limited.
NO_x	Nitrogen oxide.
Nonutility Money Pool	AEP's Nonutility Money Pool.
NSR	New Source Review.
OCC	Corporation Commission of the State of Oklahoma.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefit Plans.
OTC	Over the counter.
OVEC	Ohio Valley Electric Corporation, which is 43.47% owned by AEP.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PM	Particulate Matter.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCO	Public Utilities Commission of Ohio.

Term	Meaning
PUCT	Public Utility Commission of Texas.
Registrant Subsidiaries	AEP subsidiaries which are SEC registrants; APCo, CSPCo, I&M, OPCo, PSO and SWEPCo.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generating plant, consisting of two 1,300 MW coal-fired generating units near Rockport, Indiana, owned by AEGCo and I&M.
RTO	Regional Transmission Organization.
Sabine	Sabine Mining Company, a lignite mining company that is a consolidated variable interest entity.
SIA	System Integration Agreement.
SNF	Spent Nuclear Fuel.
SO_2	Sulfur Dioxide.
SPP	Southwest Power Pool.
Stall Unit	J. Lamar Stall Unit at Arsenal Hill Plant.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TA	Transmission Agreement dated April 1, 1984 by and among APCo, CSPCo, I&M, KPCo and OPCo, which allocates costs and benefits in connection with the operation of transmission assets.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
TEM	SUEZ Energy Marketing NA, Inc. (formerly known as Tractebel Energy Marketing, Inc.).
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
Transition Funding	AEP Texas Central Transition Funding I LLC and AEP Texas Central Transition Funding II LLC, wholly-owned subsidiaries of TCC and consolidated variable interest entities formed for the purpose of issuing and servicing securitization bonds related to Texas restructuring law.
True-up Proceeding	A filing made under the Texas Restructuring Legislation to finalize the amount of stranded costs and other true-up items and the recovery of such amounts.
Turk Plant	John W. Turk, Jr. Plant.
Utility Money Pool	AEP System's Utility Money Pool.
VIE	Variable Interest Entity.
Virginia SCC	Virginia State Corporation Commission.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary.
WVPSC	Public Service Commission of West Virginia.

FORWARD-LOOKING INFORMATION

This report made by AEP and its Registrant Subsidiaries contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Many forward-looking statements appear in "Item 7 – Management's Financial Discussion and Analysis," but there are others throughout this document which may be identified by words such as "expect," "anticipate," "intend," "plan," "believe," "will," "should," "could," "would," "project," "continue" and similar expressions, and include statements reflecting future results or guidance and statements of outlook. These matters are subject to risks and uncertainties that could cause actual results to differ materially from those projected. Forward-looking statements in this document speak only as of the date of this document. Except to the extent required by applicable law, we undertake no obligation to update or revise any forward-looking statement. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are:

- The economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns.
- Inflationary or deflationary interest rate trends.
- Volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates.
- The availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material.
- Electric load, customer growth and the impact of retail competition, particularly in Ohio.
- Weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms.
- Available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters.
- Availability of necessary generating capacity and the performance of our generating plants.
- Our ability to resolve I&M's Donald C. Cook Nuclear Plant Unit 1 restoration and outage-related issues through warranty, insurance and the regulatory process.
- Our ability to recover regulatory assets and stranded costs in connection with deregulation.
- Our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates.
- Our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates.
- New legislation, litigation and government regulation, including oversight of energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants.
- Timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance).
- Resolution of litigation.
- Our ability to constrain operation and maintenance costs.
- Our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities.
- Changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market.
- Actions of rating agencies, including changes in the ratings of debt.
- Volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities.
- Changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP.
- Accounting pronouncements periodically issued by accounting standard-setting bodies.

- The impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans, captive insurance entity and nuclear decommissioning trust and the impact on future funding requirements.
- Prices and demand for power that we generate and sell at wholesale.
- Changes in technology, particularly with respect to new, developing or alternative sources of generation.
- Other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events.
- Our ability to recover through rates or prices any remaining unrecovered investment in generating units that may be retired before the end of their previously projected useful lives.

AEP and its Registrant Subsidiaries expressly disclaim any obligation to update any forward-looking information.

AEP COMMON STOCK AND DIVIDEND INFORMATION

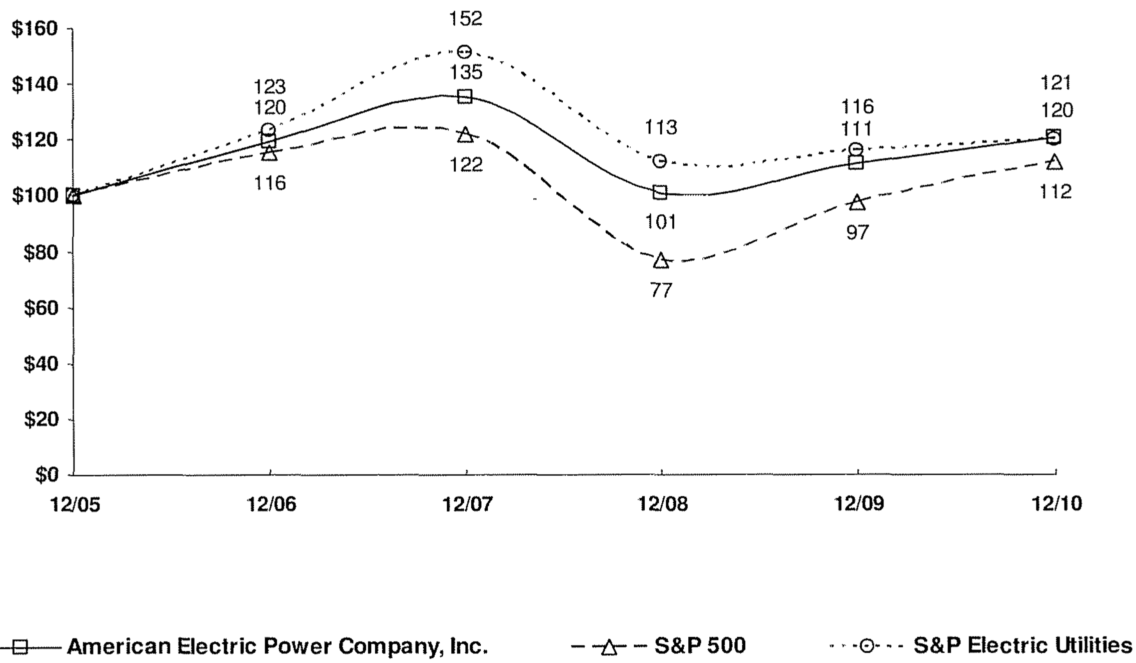
The AEP common stock quarterly high and low sales prices, quarter-end closing price and the cash dividends paid per share are shown in the following table:

Quarter Ended	High	Low	Quarter-End Closing Price	Dividend
December 31, 2010	$ 37.94	$ 34.92	$ 35.98	$ 0.46
September 30, 2010	36.93	31.87	36.23	0.42
June 30, 2010	35.00	28.17	32.30	0.42
March 31, 2010	36.86	32.68	34.18	0.41
December 31, 2009	$ 36.51	$ 29.59	$ 34.79	$ 0.41
September 30, 2009	32.36	28.07	30.99	0.41
June 30, 2009	29.16	24.75	28.89	0.41
March 31, 2009	34.34	24.00	25.26	0.41

AEP common stock is traded principally on the New York Stock Exchange. At December 31, 2010, AEP had approximately 91,000 registered shareholders.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*

Among American Electric Power Company, Inc., the S&P 500 Index
and the S&P Electric Utilities Index



*$100 invested on 12/31/05 in stock or index, including reinvestment of dividends.
Fiscal year ending December 31.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
SELECTED CONSOLIDATED FINANCIAL DATA

	2010	2009	2008	2007	2006
	(dollars in millions, except per share amounts)				
STATEMENTS OF INCOME DATA					
Total Revenues	$ 14,427	$ 13,489	$ 14,440	$ 13,380	$ 12,622
Operating Income	$ 2,663	$ 2,771	$ 2,787	$ 2,319	$ 1,966
Income Before Discontinued Operations and Extraordinary Loss	$ 1,218	$ 1,370	$ 1,376	$ 1,153	$ 1,001
Discontinued Operations, Net of Tax	-	-	12	24	10
Income Before Extraordinary Loss	1,218	1,370	1,388	1,177	1,011
Extraordinary Loss, Net of Tax	-	(5)	-	(79)	-
Net Income	1,218	1,365	1,388	1,098	1,011
Less: Net Income Attributable to Noncontrolling Interests	4	5	5	6	6
NET INCOME ATTRIBUTABLE TO AEP SHAREHOLDERS	1,214	1,360	1,383	1,092	1,005
Less: Preferred Stock Dividend Requirements of Subsidiaries	3	3	3	3	3
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1,211	$ 1,357	$ 1,380	$ 1,089	$ 1,002
BALANCE SHEETS DATA					
Total Property, Plant and Equipment	$ 53,740	$ 51,684	$ 49,710	$ 46,145	$ 42,021
Accumulated Depreciation and Amortization	18,066	17,340	16,723	16,275	15,240
Total Property, Plant and Equipment – Net	$ 35,674	$ 34,344	$ 32,987	$ 29,870	$ 26,781
Total Assets	$ 50,455	$ 48,348	$ 45,155	$ 40,319	$ 37,877
Total AEP Common Shareholders' Equity	$ 13,622	$ 13,140	$ 10,693	$ 10,079	$ 9,412
Noncontrolling Interests	$ -	$ -	$ 17	$ 18	$ 18
Cumulative Preferred Stock Not Subject to Mandatory Redemption	$ 60	$ 61	$ 61	$ 61	$ 61
Long-term Debt (a)	$ 16,811	$ 17,498	$ 15,983	$ 14,994	$ 13,698
Obligations Under Capital Leases (a)	$ 474 (b)	$ 317	$ 325	$ 371	$ 291
AEP COMMON STOCK DATA					
Basic Earnings (Loss) per Share Attributable to AEP Common Shareholders:					
Income Before Discontinued Operations and Extraordinary Loss	$ 2.53	$ 2.97	$ 3.40	$ 2.87	$ 2.52
Discontinued Operations, Net of Tax	-	-	0.03	0.06	0.02
Income Before Extraordinary Loss	2.53	2.97	3.43	2.93	2.54
Extraordinary Loss, Net of Tax	-	(0.01)	-	(0.20)	-
Total Basic Earnings per Share Attributable to AEP Common Shareholders	$ 2.53	$ 2.96	$ 3.43	$ 2.73	$ 2.54
Weighted Average Number of Basic Shares Outstanding (in millions)	479	459	402	399	394
Market Price Range:					
High	$ 37.94	$ 36.51	$ 49.11	$ 51.24	$ 43.13
Low	$ 28.17	$ 24.00	$ 25.54	$ 41.67	$ 32.27
Year-end Market Price	$ 35.98	$ 34.79	$ 33.28	$ 46.56	$ 42.58
Cash Dividends Paid per AEP Common Share	$ 1.71	$ 1.64	$ 1.64	$ 1.58	$ 1.50
Dividend Payout Ratio	67.59%	55.41%	47.8%	57.9%	59.1%
Book Value per AEP Common Share	$ 28.32	$ 27.49	$ 26.35	$ 25.17	$ 23.73

(a) Includes portion due within one year.
(b) Obligations Under Capital Leases increased primarily due to capital leases under new master lease agreements for property that was previously leased under operating leases.

EXECUTIVE OVERVIEW

Company Overview

American Electric Power Company, Inc. (AEP) is one of the largest investor-owned electric public utility holding companies in the United States. Our electric utility operating companies provide generation, transmission and distribution services to more than five million retail customers in Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia.

We operate an extensive portfolio of assets including:

- Almost 39,000 megawatts of generating capacity, one of the largest complements of generation in the U.S., the majority of which provides a significant cost advantage in most of our market areas.
- Approximately 39,000 miles of transmission lines, including 2,116 miles of 765kV lines, the backbone of the electric interconnection grid in the Eastern U.S.
- Approximately 220,000 miles of distribution lines that deliver electricity to 5.3 million customers.
- Substantial commodity transportation assets (more than 9,000 railcars, approximately 3,300 barges, 62 towboats, 29 harbor boats and a coal handling terminal with 18 million tons of annual capacity).

Economic Conditions

Retail margins increased during 2010 due to successful rate proceedings in various jurisdictions and higher residential and commercial demand for electricity as a result of favorable weather throughout our service territories. Industrial sales increased 5% in 2010 in comparison to the recessionary lows of 2009. We forecast a 1% increase in commercial sales and 2% increases in both our residential and industrial sales in 2011 as a result of anticipated slow economic growth. Our forecasted industrial sales growth of 2% is due to the announcement of increased production by Ormet, a large aluminum manufacturer in Ohio, and announced expansions of several refineries in our Texas service territory.

Regulatory Activity

The table below summarizes our significant 2010 regulatory activities:

Jurisdiction	Annual Approved Base Rate Change	Annual Rider Surcharge Rate Change	Approved Return on Common Equity	Effective Date
	(in millions)			
Kentucky	$ 63.7	$ -	10.50%	July 2010
Michigan	35.7	3.3 (a)	10.35%	December 2010
Oklahoma	30.3	(30.3)	10.15%	February 2011
Texas	15.0	10.0 (b)	10.33%	May 2010
Virginia	61.5	-	10.53%	August 2010

(a) The MPSC granted I&M recovery of $6.6 million of customer choice implementation costs over a two year period beginning April 2011.
(b) The PUCT granted SWEPCo a $10 million one-year surcharge rider to recover additional vegetation management costs which began in May 2010.

In Ohio, several notices of appeal are outstanding at the Supreme Court of Ohio relating to significant issues in the determination of the approved 2009 – 2011 ESP rates. In January 2011, the PUCO issued an order that determined that OPCo's 2009 earnings were not significantly excessive but determined relevant CSPCo 2009 earnings were significantly excessive. As a result, the PUCO ordered CSPCo to refund $43 million of its earnings to customers, which was recorded on CSPCo's December 2010 books. Also, in January 2011, CSPCo and OPCo filed an application with the PUCO to approve a new ESP that includes a standard service offer pricing for generation effective with the first billing cycle of January 2012 through the last billing cycle of May 2014. Customer class rates individually vary, but on average, customers would experience net base generation increases of 1.4% in 2012 and 2.7% for the period January 2013 through May 2014.

In West Virginia, a settlement agreement was filed with the WVPSC in December 2010 to increase annual base rates by $60 million, effective March 2011. The settlement agreement allows APCo to defer and amortize up to $18 million of previously expensed 2009 incremental storm expenses over a period of eight years. A decision from the WVPSC is expected in March 2011.

Cost Reduction Initiatives

Due to the continued slow recovery in the U.S. economy and a corresponding negative impact on energy consumption, the AEP System implemented cost reduction initiatives in the second quarter of 2010 to reduce its workforce by 11.5% and reduce Other Operation and Maintenance spending. Achieving these goals involved identifying process improvements, streamlining organizational designs and developing other efficiencies that will deliver additional savings. In 2010, we recorded $293 million of pretax expense related to these cost reduction initiatives. Starting with the third quarter of 2010, we realized cost savings in Other Operation and Maintenance expenses on our Consolidated Statements of Income and anticipate continued savings to help offset future inflationary impacts.

Turk Plant

SWEPCo is currently constructing the Turk Plant, a new base load 600 MW coal generating unit in Arkansas, which is expected to be in service in 2012. SWEPCo owns 73% (440 MW) of the Turk Plant and will operate the completed facility. SWEPCo's share of construction costs is currently estimated to cost $1.3 billion, excluding AFUDC, plus an additional $125 million for transmission, excluding AFUDC. The APSC, LPSC and PUCT approved SWEPCo's original application to build the Turk Plant. Various proceedings are pending that challenge the Turk Plant's construction, its approved wetlands and air permits and its transmission line certificate of environmental compatibility and public need. In 2010, the motions for preliminary injunction were partially granted and upheld on appeal pending a hearing. According to the preliminary injunction, all uncompleted construction work associated with wetlands, streams or rivers at the Turk Plant must immediately stop. Mitigation measures required by the permit are authorized and may be completed. The preliminary injunction affects portions of the water intake and associated piping and portions of the transmission lines. A hearing on SWEPCo's appeal is scheduled for March 2011.

In June 2010, the Arkansas Supreme Court denied motions for rehearing filed by the APSC and SWEPCo related to the reversal of the APSC's earlier grant of a Certificate of Environmental Compatibility and Public Need (CECPN) for SWEPCo's 88 MW Arkansas portion of the Turk Plant. As a result, in June 2010, SWEPCo filed notice with the APSC of its intent to proceed with construction of the Turk Plant but that SWEPCo no longer intends to pursue a CECPN to seek recovery of its Arkansas portion of Turk Plant costs in Arkansas retail rates. The APSC issued an order which reversed and set aside the previously granted CECPN.

Management expects that SWEPCo will ultimately be able to complete construction of the Turk Plant and related transmission facilities and place those facilities in service. However, if SWEPCo is unable to complete the Turk Plant construction and place the Turk Plant in service or if SWEPCo cannot recover all of its investment in and expenses related to the Turk Plant, it would materially reduce future net income and cash flows and materially impact financial condition. See "Turk Plant" section of Note 4.

Settlement with Bank of America

In February 2011, we reached a settlement with BOA and paid $425 million in full settlement of all claims against us. We also received title to 55 BCF of cushion gas in the Bammel storage facility as part of the settlement. The effect of the settlement had no impact on our financial statements for the year ended December 31, 2010. We do not expect the effect of the settlement to have a material impact on our 2011 consolidated net income.

Ohio Customer Choice

In our Ohio service territory, various competitive retail electric service (CRES) providers are targeting retail customers by offering alternative generation service. As of December 31, 2010, approximately 5,000 Ohio retail customers (primarily CSPCo customers) have switched to alternative CRES providers. As a result, in comparison to 2009, we lost approximately $16 million of generation related gross margin in 2010 and currently forecast incremental lost margins of approximately $54 million for 2011. We anticipate recovery of a portion of this lost margin through off-system sales and our newly created CRES provider. Our CRES provider will target retail customers in Ohio, both within and outside of our retail service territory.

Termination of AEP Power Pool

Originally approved by the FERC in 1951 and subsequently amended in 1951, 1962, 1975 1979 (twice) and 1980, the Interconnection Agreement establishes the AEP Power Pool which permits the AEP East companies to pool their generation assets on a cost basis. In December 2010, each member gave notice to AEPSC and the other AEP Power Pool members of its decision to terminate the Interconnection Agreement effective January 1, 2014 or such other date approved by the FERC, subject to state regulatory input. It is unknown at this time whether the AEP Power Pool will be replaced by a new agreement among some or all of the members, whether individual companies will enter into bilateral or multi-party contracts with each other for power sales and purchases or asset transfers or if each company will choose to operate independently. The decision to terminate is subject to management's ongoing evaluation. The AEP Power Pool members may revoke their notices of termination. If members of the current AEP Power Pool experience decreases in revenues or increases in costs as a result of the termination of the AEP Power Pool and are unable to recover the change in revenues and costs through rates, prices or additional sales, it could have an adverse impact on future net income and cash flows.

Transmission Agreement

The AEP East companies are parties to a Transmission Agreement defining how they share the costs associated with their relative ownership of transmission assets. This sharing was based upon each company's MLR until the FERC approved a new Transmission Agreement effective November 1, 2010. The new Transmission Agreement will be phased-in for retail rates over periods of up to four years, adds KGPCo and WPCo as parties to the agreement and changes the allocation method. Our recovery mechanism for transmission costs is through our base rates. State regulatory phase-in of the new agreement may limit our ability to fully recover our transmission costs.

Cook Plant Unit 1 Fire and Shutdown

In September 2008, I&M shut down Cook Plant Unit 1 (Unit 1) due to turbine vibrations, caused by blade failure, which resulted in a fire on the electric generator. Repair of the property damage and replacement of the turbine rotors and other equipment could cost up to approximately $395 million. Management believes that I&M should recover a significant portion of repair and replacement costs through the turbine vendor's warranty, insurance and the regulatory process. I&M repaired Unit 1 and it resumed operations in December 2009 at slightly reduced power. The Unit 1 rotors were repaired and reinstalled due to the extensive lead time required to manufacture and install new turbine rotors. As a result, the replacement of the repaired turbine rotors and other equipment is scheduled for the Unit 1 planned outage in the fall of 2011. If the ultimate costs of the incident are not covered by warranty, insurance or through the related regulatory process or if any future regulatory proceedings are adverse, it could have an adverse impact on net income, cash flows and financial condition. See "Cook Plant Unit 1 Fire and Shutdown" section of Note 6.

Texas Restructuring Appeals

Pursuant to PUCT restructuring orders, TCC securitized net recoverable stranded generation costs of $2.5 billion and is recovering the principal and interest on the securitization bonds through the end of 2020. TCC also refunded other net true-up regulatory liabilities of $375 million during the period October 2006 through June 2008 via a CTC credit rate rider under PUCT restructuring orders. TCC and intervenors appealed the PUCT's true-up related orders. After rulings from the Texas District Court and the Texas Court of Appeals, TCC, the PUCT and intervenors filed petitions for review with the Texas Supreme Court. Review is discretionary and the Texas Supreme Court has not yet determined if it will grant review. See "Texas Restructuring Appeals" section of Note 4.

Mountaineer Carbon Capture and Storage

Product Validation Facility (PVF)

APCo and ALSTOM Power, Inc., an unrelated third party, jointly constructed a CO_2 capture validation facility, which was placed into service in September 2009. APCo also constructed and owns the necessary facilities to store the CO_2. In APCo's July 2009 Virginia base rate filing and May 2010 West Virginia base rate filing, APCo requested recovery of and a return on its Virginia and West Virginia jurisdictional share of its project costs and recovery of the related asset retirement obligation regulatory asset amortization and accretion. In July 2010, the Virginia SCC issued a base rate order that denied recovery of the Virginia share of the PVF costs, which resulted in a pretax write-off of approximately $54 million in the second quarter of 2010. In December 2010, a settlement agreement was filed with the WVPSC to increase annual base rates by $60 million, effective March 2011. A decision from the WVPSC is expected in March 2011. As of December 31, 2010, APCo has recorded a noncurrent regulatory asset of $60 million related to the PVF. If APCo cannot recover its remaining investments in and expenses related to the PVF, it would reduce future net income and cash flows and impact financial condition. See "Mountaineer Carbon Capture and Storage Project" section of Note 4.

Carbon Capture and Sequestration Project with the Department of Energy (DOE)

During 2010, AEPSC, on behalf of APCo, began the project definition stage for the potential construction of a new commercial scale carbon capture and sequestration (CCS) facility under consideration at the Mountaineer Plant. AEPSC, on behalf of APCo, applied for and was selected to receive funding from the DOE for the project. The DOE will fund 50% of allowable costs incurred for the CCS facility up to a maximum of $334 million. A Front-End Engineering and Design (FEED) study, scheduled for completion during the third quarter of 2011, will refine the total cost estimate for the CCS facility. Results from the FEED study will be evaluated by management before any decision is made to seek the necessary regulatory approvals to build the CCS facility. As of December 31, 2010, APCo has incurred $14 million in total costs and has received $5 million of DOE funding resulting in a net $9 million balance included in Construction Work In Progress on the Consolidated Balance Sheets. If APCo is unable to recover the costs of the CCS project, it would reduce future net income and cash flows. See "Mountaineer Carbon Capture and Storage Project" section of Note 4.

LITIGATION

In the ordinary course of business, we are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot state what the eventual resolution will be or the timing and amount of any loss, fine or penalty may be. We assess the probability of loss for each contingency and accrue a liability for cases that have a probable likelihood of loss if the loss can be estimated. For details on our regulatory proceedings and pending litigation see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies. Adverse results in these proceedings have the potential to materially affect our net income.

ENVIRONMENTAL ISSUES

We are implementing a substantial capital investment program and incurring additional operational costs to comply with new environmental control requirements. We will need to make additional investments and operational changes in response to existing and anticipated requirements such as CAA requirements to reduce emissions of SO_2, NO_x, PM and hazardous air pollutants from fossil fuel-fired power plants and new proposals governing the beneficial use and disposal of coal combustion products.

We are engaged in litigation about environmental issues, have been notified of potential responsibility for the clean-up of contaminated sites and incur costs for disposal of SNF and future decommissioning of our nuclear units. We are also engaged in the development of possible future requirements to reduce CO_2 emissions to address concerns about global climate change.

Clean Air Act Requirements

The CAA establishes a comprehensive program to protect and improve the nation's air quality and control sources of air emissions. The states implement and administer many of these programs and could impose additional or more stringent requirements. Notable developments in CAA regulatory requirements affecting our operations are discussed briefly below.

The Federal EPA issued the Clean Air Interstate Rule (CAIR) in 2005 requiring specific reductions in SO_2 and NO_x emissions from power plants. In 2008, the D.C. Circuit Court of Appeals issued a decision remanding CAIR to the Federal EPA. CAIR remains in effect while a new rulemaking is conducted. Nearly all of the states in which our power plants are located are covered by CAIR. In July 2010, the Federal EPA issued a proposed rule (Transport Rule) to replace CAIR that would impose new and more stringent requirements to control SO_2 and NO_x emissions from fossil fuel-fired electric generating units in 31 states and the District of Columbia. Each state covered by the Transport Rule is assigned an allowance budget for SO_2 and/or NO_x. Limited interstate trading is allowed on a sub-regional basis and intrastate trading is allowed among generating units. Certain of our western states (Texas, Arkansas and Oklahoma) would be subject to only the seasonal NO_x program, with new limits that are proposed to take effect in 2012. The remainder of the states in which we operate would be subject to seasonal and annual NO_x programs and an annual SO_2 emissions reduction program that takes effect in two phases. The first phase becomes effective in 2012 and requires approximately one million tons per year more SO_2 emission reductions across the region than would have been required under CAIR. The second phase takes effect in 2014 and reduces SO_2 emissions by an additional 800,000 tons per year. The SO_2 and NO_x programs rely on newly-created allowances rather than relying on the CAIR NO_x allowances or the Title IV Acid Rain Program allowances used in the CAIR rule. The time frames for and stringency of the additional emission reductions, coupled with the lack of robust interstate trading and the elimination of historic allowance banks, pose significant concerns for the AEP System and our electric utility customers, as these features could accelerate unit retirements, increase capital requirements, constrain operations, decrease reliability and unfavorably impact financial condition if the increased costs are not recovered in rates or market prices. The Federal EPA requested comments on a scheme based exclusively on intrastate trading of allowances or a scheme that establishes unit-by-unit emission rates. Either of these options would provide less flexibility and exacerbate the negative impact of the rule. The proposal indicates that the requirements are expected to be finalized in June 2011 and be effective January 1, 2012.

The Federal EPA issued a Clean Air Mercury Rule (CAMR) setting mercury standards for new coal-fired power plants and requiring all states to issue new state implementation plans (SIPs) including mercury requirements for existing coal-fired power plants. The CAMR was vacated and remanded to the Federal EPA by the D.C. Circuit Court of Appeals in 2008.

Under the terms of a consent decree, the Federal EPA is required to issue final maximum achievable control technology (MACT) standards for coal and oil-fired power plants by November 2011. The Federal EPA has substantial discretion in determining how to structure the MACT standards. We will urge the Federal EPA to carefully consider all of the options available so that costly and inefficient control requirements are not imposed regardless of unit size, age or other operating characteristics. However, we have approximately 5,000 MW of older coal units, including 2,000 MW of older coal-fired capacity already subject to control requirements under the NSR consent decree, for which it may be economically inefficient to install scrubbers or other environmental controls. The timing and ultimate disposition of those units will be affected by: (a) the MACT standards and other environmental regulations, (b) the economics of maintaining the units, (c) demand for electricity, (d) availability and cost of replacement power and (e) regulatory decisions about cost recovery of the remaining investment in those units.

The Federal EPA issued a Clean Air Visibility Rule (CAVR), detailing how the CAA's best available retrofit technology requirements will be applied to facilities built between 1962 and 1977 that emit more than 250 tons per year of certain pollutants in specific industrial categories, including power plants. CAVR will be implemented through individual SIPs or, if SIPs are not adequate or are not developed on schedule, through federal implementation plans (FIPs). The Federal EPA has proposed disapproval of SIPs in a few states, and proposed more stringent control requirements for affected units in those states. If the Federal EPA takes such action in the states where our facilities are located, it could increase the costs of compliance, accelerate the installation of required controls, and/or force the premature retirement of existing units.

In 2009, the Federal EPA issued a final mandatory reporting rule for CO_2 and other greenhouse gases covering a broad range of facilities emitting in excess of 25,000 tons of CO_2 emissions per year. The Federal EPA issued a final endangerment finding for greenhouse gas emissions from new motor vehicles in 2009 and final rules limiting CO_2 emissions from new motor vehicles in May 2010. The Federal EPA determined that greenhouse gas emissions from stationary sources will be subject to regulation under the CAA beginning January 2011 and finalized its proposed scheme to streamline and phase-in regulation of stationary source CO_2 emissions through the NSR prevention of significant deterioration and Title V operating permit programs through the issuance of final federal rules, SIP calls and FIPs. The Federal EPA is reconsidering whether to include CO_2 emissions in a number of stationary source standards, including standards that apply to new and modified electric utility units and announced a settlement agreement to issue proposed new source performance standards for utility boilers. It is not possible at this time to estimate the costs of compliance with these new standards, but they may be material.

The Federal EPA has also issued new, more stringent national ambient air quality standards (NAAQS) for SO_2, NO_x and lead, and is currently reviewing the NAAQS for ozone and PM. States are in the process of evaluating the attainment status and need for additional control measures in order to attain and maintain the new NAAQS and may develop additional requirements for our facilities as a result of those evaluations. We cannot currently predict the nature, stringency or timing of those requirements.

Estimated Air Quality Environmental Investments

The CAIR, CAVR and the consent decree signed to settle the NSR litigation require us to make significant additional investments, some of which are estimable. Our estimates are subject to significant uncertainties and will be affected by any changes in the outcome of several interrelated variables and assumptions, including: (a) the timing of implementation, (b) required levels of reductions, (c) methods for allocation of allowances and (d) our selected compliance alternatives and their costs. These obligations may also be affected or altered by the development of new regulations described above. In short, we cannot estimate our compliance costs with certainty and the actual costs to comply could differ significantly from the estimates discussed below.

The CAIR, CAVR and commitments in the consent decree will require installation of additional controls on our power plants through 2020. We plan to install additional scrubbers on 6,770 MW for SO_2 control. From 2011 to 2020, we estimate total environmental investment to meet these requirements of $10.6 billion including investment in scrubbers and other SO_2 equipment of approximately $5.9 billion. These estimates are highly uncertain due to the variability associated with: (a) the states' implementation of these regulatory programs, including the potential for SIPs or FIPS that impose standards more stringent than CAIR or CAVR, (b) additional rulemaking activities in response to the court decisions remanding the CAIR and CAMR, (c) the actual performance of the pollution control technologies installed on our units, (d) changes in costs for new pollution controls, (e) new generating technology developments and (f) other factors. Associated operational and maintenance expenses will also increase during those years. We cannot estimate these additional operational and maintenance costs due to the uncertainties described above, but they are expected to be significant. Estimated construction expenditures are subject to periodic review and modification.

We will seek recovery of expenditures for pollution control technologies, replacement or additional generation and associated operating costs from customers through our regulated rates. We should be able to recover these expenditures through market prices in deregulated jurisdictions. If not, those costs could adversely affect future net income, cash flows and possibly financial condition.

Coal Combustion Residual Rule

In June 2010, the Federal EPA published a proposed rule to regulate the disposal and beneficial re-use of coal combustion residuals, including fly ash and bottom ash generated at our coal-fired electric generating units. The rule contains two alternative proposals, one that would impose federal hazardous waste disposal and management standards on these materials and one that would allow states to retain primary authority to regulate the beneficial re-use and disposal of these materials under state solid waste management standards, including minimum federal standards for disposal and management. Both proposals would impose stringent requirements for the construction of new coal ash landfills and would require existing unlined surface impoundments to upgrade to the new standards or stop receiving coal ash and initiate closure within five years of the issuance of a final rule.

Currently, approximately 40% of the coal ash and other residual products from our generating facilities are re-used in the production of cement and wallboard, as structural fill or soil amendments, as abrasives or road treatment materials and for other beneficial uses. Certain of these uses would no longer be available and others are likely to significantly decline if coal ash and related materials are classified as hazardous wastes. In addition, we currently use surface impoundments and landfills to manage these materials at our generating facilities and will incur significant costs to upgrade or close and replace these existing facilities. We estimate that the potential compliance costs associated with the proposed solid waste management alternative could be as high as $3.9 billion for units across the AEP System. Regulation of these materials as hazardous wastes would significantly increase these costs. We will seek recovery of expenditures for pollution control technologies and associated costs from customers through our regulated rates (in regulated jurisdictions). We should be able to recover these expenditures through market prices in deregulated jurisdictions. If not, these costs could adversely affect future net income, cash flows and possibly financial condition.

Global Warming

National public policy makers and regulators in the 11 states we serve have conflicting views on global warming. We are focused on taking, in the short term, actions that we see as prudent, such as improving energy efficiency, investing in developing cost-effective and less carbon-intensive technologies and evaluating our assets across a range of plausible scenarios and outcomes. We are also active participants in a variety of public policy discussions at state and federal levels to assure that proposed new requirements are feasible and the economies of the states we serve are not placed at a competitive disadvantage.

We believe that this is a global issue and that the United States should assume a leadership role in developing a new international approach that will address growing emissions of CO_2 and other greenhouse gases (generally referred to as CO_2 in this discussion) from all nations, including developing countries. We support a reasonable approach to CO_2 emission reductions that recognizes a reliable and affordable electric supply is vital to economic stability and that allows sufficient time for technology development. We proposed to national policy makers that national and international policy for reasonable CO_2 controls should involve the following principles:

- Comprehensiveness
- Cost-effectiveness
- Realistic emission reduction objectives
- Reliable monitoring and verification mechanisms
- Incentives to develop and deploy CO_2 reduction technologies
- Removal of regulatory or economic barriers to CO_2 emission reductions
- Recognition for early actions/investments in CO_2 reduction/mitigation
- Inclusion of adjustment provisions if largest emitters in developing world do not take action

For additional information on global warming, see Part I of the Annual Report under the headings entitled "Business – General – Environmental and Other Matters – Global Warming."

While comprehensive economy-wide regulation of CO_2 emissions might be achieved through future legislation, Congress has yet to enact such legislation. The Federal EPA continues to take action to regulate CO_2 emissions under the existing requirements of the CAA discussed above.

Our fossil fuel-fired generating units are very large sources of CO_2 emissions. If substantial CO_2 emission reductions are required, there will be significant increases in capital expenditures and operating costs which would impact the ultimate retirement of older, less-efficient, coal-fired units. To the extent we install additional controls on our generating plants to limit CO_2 emissions and receive regulatory approvals to increase our rates, cost recovery could have a positive effect on future earnings. Prudently incurred capital investments made by our subsidiaries in rate-regulated jurisdictions to comply with legal requirements and benefit customers are generally included in rate base for recovery and earn a return on investment. We would expect these principles to apply to investments made to address new environmental requirements. However, requests for rate increases reflecting these costs can affect us adversely because our regulators could limit the amount or timing of increased costs that we would recover through higher rates. In addition, to the extent our costs are relatively higher than our competitors' costs, such as operators of nuclear and natural gas based generation, it could reduce our off-system sales or cause us to lose customers in jurisdictions that permit customers to choose their supplier of generation service.

Several states have adopted programs that directly regulate CO_2 emissions from power plants, but none of these programs are currently in effect in states where we have generating facilities. Certain of our states have passed legislation establishing renewable energy, alternative energy and/or energy efficiency requirements (including Ohio, Michigan, Texas and Virginia). We are taking steps to comply with these requirements. In order to meet these requirements and as a key part of our corporate sustainability effort, we pledged to increase our wind power by an additional 2,000 MW from 2007 levels by 2011. By the end of 2010, we secured, through power purchase agreements, an additional 1,111 MW of wind power. To the extent demand for renewable energy from wind power increases, it could have a positive effect on future earnings from our transmission activities. For example, a project in Texas would build new transmission lines to transport electricity from planned wind energy generation in west Texas to more densely populated areas in eastern Texas.

We have taken measurable, voluntary actions to reduce and offset our CO_2 emissions. We participated in a number of voluntary programs to monitor, mitigate and reduce CO_2 emissions, but many of these programs have been discontinued due to anticipated legislative or regulatory actions. Through the end of 2009, we reduced our emissions by a cumulative 94 million metric tons from adjusted baseline levels in 1998 through 2001 as a result of these voluntary actions. Our total CO_2 emissions in 2009 were 136 million metric tons. We estimate that our 2010 emissions were approximately 140 million metric tons.

Certain groups have filed lawsuits alleging that emissions of CO_2 are a "public nuisance" and seeking injunctive relief and/or damages from small groups of coal-fired electricity generators, petroleum refiners and marketers, coal companies and others. We have been named in pending lawsuits, which we are vigorously defending. It is not possible to predict the outcome of these lawsuits or their impact on our operations or financial condition. See "Carbon Dioxide Public Nuisance Claims" and "Alaskan Villages' Claims" sections of Note 6.

Future federal and state legislation or regulations that mandate limits on the emission of CO_2 would result in significant increases in capital expenditures and operating costs, which, in turn, could lead to increased liquidity needs and higher financing costs. Excessive costs to comply with future legislation or regulations might force our utility subsidiaries to close some coal-fired facilities and could lead to possible impairment of assets. As a result, mandatory limits could have a material adverse impact on our net income, cash flows and financial condition.

Global warming creates the potential for physical and financial risk. The materiality of the risks depends on whether any physical changes occur quickly or over several decades and the extent and nature of those changes. Physical risks from climate change could include changes in weather conditions. Our customers' energy needs currently vary with weather conditions, primarily temperature and humidity. For residential customers, heating and cooling today represent their largest energy use. To the extent weather patterns change significantly, customers' energy use could increase or decrease depending on the duration and magnitude of any changes. Increased energy use due to weather changes could require us to invest in more generating assets, transmission and other infrastructure to serve increased load, driving the overall cost of electricity higher. Decreased energy use due to weather changes could affect our financial condition through lower sales and decreased revenues. Extreme weather conditions in general require more system backup, adding to costs, and can contribute to increased system stresses, including service interruptions and increased storm restoration costs. We may not recover all costs related to mitigating these physical and financial risks. Weather conditions outside of our service territory could also have an impact on our revenues, either directly through changes in the patterns of our off-system power purchases and sales or indirectly through demographic changes as people adapt to changing weather. We buy and sell electricity depending upon system needs and market opportunities. Extreme weather conditions that create high energy demand could raise electricity prices, which could increase the cost of energy we provide to our customers and could provide opportunity for increased wholesale sales.

To the extent climate change impacts a region's economic health, it could also impact our revenues. Our financial performance is tied to the health of the regional economies we serve. The price of energy, as a factor in a region's cost of living as well as an important input into the cost of goods, has an impact on the economic health of our communities. The cost of additional regulatory requirements would normally be borne by consumers through higher prices for energy and purchased goods.

RESULTS OF OPERATIONS

SEGMENTS

Our primary business is our electric utility operations. Within our Utility Operations segment, we centrally dispatch generation assets and manage our overall utility operations on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight. While our Utility Operations segment remains our primary business segment, other segments include our AEP River Operations segment with significant barging activities and our Generation and Marketing segment, which includes our nonregulated generating, marketing and risk management activities primarily in the ERCOT market area and to a lesser extent Ohio in PJM and MISO. Intersegment sales and transfers are generally based on underlying contractual arrangements and agreements.

Our reportable segments and their related business activities are as follows:

Utility Operations

- Generation of electricity for sale to U.S. retail and wholesale customers.
- Electricity transmission and distribution in the U.S.

AEP River Operations

- Commercial barging operations that annually transport approximately 39 million tons of coal and dry bulk commodities primarily on the Ohio, Illinois and lower Mississippi Rivers. Approximately 46% of the barging is for transportation of agricultural products, 25% for coal, 11% for steel and 18% for other commodities.

Generation and Marketing

- Wind farms and marketing and risk management activities primarily in ERCOT and to a lesser extent Ohio in PJM and MISO.

The table below presents our consolidated Income (Loss) Before Discontinued Operations and Extraordinary Loss by segment for the years ended December 31, 2010, 2009 and 2008.

	Years Ended December 31, 2010	2009	2008
		(in millions)	
Utility Operations	$ 1,201	$ 1,329	$ 1,123
AEP River Operations	37	47	55
Generation and Marketing	25	41	65
All Other (a)	(45)	(47)	133
Income Before Discontinued Operations and Extraordinary Loss	$ 1,218	$ 1,370	$ 1,376

(a) While not considered a business segment, All Other includes:
- Parent's guarantee revenue received from affiliates, investment income, interest income and interest expense, and other nonallocated costs.
- Tax and interest expense adjustments related to our UK operations which were sold in 2004 and 2002.
- Forward natural gas contracts that were not sold with our natural gas pipeline and storage operations in 2004 and 2005. These contracts are financial derivatives which settle and expire in 2011.
- The 2008 cash settlement of a purchase power and sale agreement with TEM related to the Plaquemine Cogeneration Facility which was sold in 2006. The cash settlement of $255 million ($164 million, net of tax) is included in Net Income.
- Revenue sharing related to the Plaquemine Cogeneration Facility.

AEP CONSOLIDATED

2010 Compared to 2009

Income Before Discontinued Operations and Extraordinary Loss in 2010 decreased $152 million compared to 2009 primarily due to $185 million of charges incurred (net of tax) related to cost reduction initiatives. In 2010, we conducted cost reduction initiatives to reduce both labor and non-labor expenses.

Average basic shares outstanding increased to 479 million in 2010 from 459 million in 2009 primarily due to the April 2009 issuance of 69 million shares of AEP common stock. Actual shares outstanding were 481 million as of December 31, 2010.

2009 Compared to 2008

Income Before Discontinued Operations and Extraordinary Loss in 2009 decreased $6 million compared to 2008 primarily due to income in 2008 from the cash settlement of a purchase power and sale agreement with TEM offset by an increase in income from our Utility Operations segment. The increase in Utility Operations segment net income primarily relates to rate increases in our Indiana, Ohio, Oklahoma and Virginia service territories partially offset by lower industrial sales as well as lower off-system sales margins due to lower sales volumes and lower market prices.

Average basic shares outstanding increased to 459 million in 2009 from 402 million in 2008 primarily due to the April 2009 issuance of 69 million shares of AEP common stock. Actual shares outstanding were 478 million as of December 31, 2009.

Our results of operations are discussed below by operating segment.

UTILITY OPERATIONS

We believe that a discussion of the results from our Utility Operations segment on a gross margin basis is most appropriate in order to further understand the key drivers of the segment. Gross margin represents total revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances and purchased power.

	Years Ended December 31,		
	2010	**2009**	**2008**
		(in millions)	
Total Revenues	$ 13,791	$ 12,803	$ 13,566
Fuel and Purchased Power	4,996	4,420	5,622
Gross Margin	8,795	8,383	7,944
Depreciation and Amortization	1,598	1,561	1,450
Other Operating Expenses	4,573	4,162	4,114
Operating Income	2,624	2,660	2,380
Other Income, Net	169	138	173
Interest Expense	942	916	915
Income Tax Expense	650	553	515
Income Before Discontinued Operations and Extraordinary Loss	$ 1,201	$ 1,329	$ 1,123

KWH Sales/Degree Days

Summary of KWH Energy Sales for Utility Operations

	Years Ended December 31,		
	2010	**2009**	**2008**
	(in millions of KWH)		
Retail:			
Residential	61,944	58,232	58,892
Commercial	50,748	49,925	50,382
Industrial	57,333	54,428	64,508
Miscellaneous	3,083	3,048	3,114
Total Retail (a)	173,108	165,633	176,896
Wholesale	32,581	29,670	43,068
Total KWHs	205,689	195,303	219,964

(a) Includes energy delivered to customers served by AEP's Texas Wires Companies.

Cooling degree days and heating degree days are metrics commonly used in the utility industry as a measure of the impact of weather on net income. In general, degree day changes in our eastern region have a larger effect on net income than changes in our western region due to the relative size of the two regions and the number of customers within each region.

Summary of Heating and Cooling Degree Days for Utility Operations

	Years Ended December 31,		
	2010	**2009**	**2008**
	(in degree days)		
Eastern Region			
Actual - Heating (a)	3,222	3,018	3,154
Normal - Heating (b)	2,983	3,040	3,018
Actual - Cooling (c)	1,307	816	949
Normal - Cooling (b)	1,002	1,011	986
Western Region			
Actual - Heating (a)	1,112	970	992
Normal - Heating (b)	980	984	1,010
Actual - Cooling (d)	2,515	2,439	2,252
Normal - Cooling (b)	2,339	2,344	2,320

(a) Eastern Region and Western Region heating degree days are calculated on a 55 degree temperature base.
(b) Normal Heating/Cooling represents the thirty-year average of degree days.
(c) Eastern Region cooling degree days are calculated on a 65 degree temperature base.
(d) Western Region cooling degree days are calculated on a 65 degree temperature base for PSO/SWEPCo and a 70 degree temperature base for TCC/TNC.

2010 Compared to 2009

Reconciliation of Year Ended December 31, 2009 to Year Ended December 31, 2010
Income from Utility Operations Before Discontinued Operations and Extraordinary Loss
(in millions)

Year Ended December 31, 2009	$	1,329
Changes in Gross Margin:		
Retail Margins		601
Off-system Sales		53
Transmission Revenues		15
Other Revenues		(257)
Total Change in Gross Margin		412
Total Expenses and Other:		
Other Operation and Maintenance		(351)
Depreciation and Amortization		(37)
Taxes Other Than Income Taxes		(60)
Interest and Investment Income		5
Carrying Costs Income		23
Allowance for Equity Funds Used During Construction		(5)
Interest Expense		(26)
Equity Earnings of Unconsolidated Subsidiaries		8
Total Expenses and Other		(443)
Income Tax Expense		(97)
Year Ended December 31, 2010	$	1,201

The major components of the increase in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased power were as follows:

- **Retail Margins** increased $601 million primarily due to the following:
  - Successful rate proceedings in our service territories which include:
    - A $138 million increase in the recovery of E&R costs in Virginia, costs related to the Transmission Rate Adjustment Clause in Virginia and construction financing costs in West Virginia.
    - A $49 million increase in the recovery of advanced metering costs in Texas.
    - A $43 million net rate increase for KPCo.
    - A $42 million net rate increase for SWEPCo.
    - A $39 million net rate increase for I&M.
    - A $37 million net rate increase for PSO.
    - A $14 million net rate increase in our other jurisdictions.
    - For the increases described above, $183 million of these increases relate to riders/trackers which have corresponding increases in other expense items.
  - A $229 million increase in weather-related usage primarily due to a 60% increase in cooling degree days in our eastern service territory and 7% and 15% increases in heating degree days in our eastern and western service territories, respectively.
  - A $78 million increase due to higher fuel and purchased power costs recorded in 2009 related to the Cook Plant Unit 1 (Unit 1) shutdown. This increase was offset by a corresponding decrease in Other Revenues as discussed below.

  These increases were partially offset by:
  - A $43 million decrease due to a refund provision for the 2009 Significantly Excessive Earnings Test (SEET).
  - A $38 million decrease due to the termination of an I&M unit power agreement.

- **Margins from Off-system Sales** increased $53 million primarily due to increased prices and higher physical sales volumes in our eastern service territory, partially offset by lower trading and marketing margins.
- **Transmission Revenues** increased $15 million primarily due to increased revenues in the ERCOT, PJM and SPP regions.
- **Other Revenues** decreased $257 million primarily due to the Cook Plant accidental outage insurance proceeds of $185 million which ended when Unit 1 returned to service in December 2009. I&M reduced customer bills by approximately $78 million in 2009 for the cost of replacement power resulting from the Unit 1 outage. This decrease in insurance proceeds was offset by a corresponding increase in Retail Margins as discussed above. Other Revenues also decreased due to lower gains on sales of emission allowances of $29 million, partially offset by sharing with customers in certain fuel clauses. This decrease in gains on sales of emission allowances was the result of lower market prices.

Total Expenses and Other and Income Tax Expense changed between years as follows:

- **Other Operation and Maintenance** expenses increased $351 million primarily due to the following:
  - A $280 million increase due to expenses related to the cost reduction initiatives. In 2010, management conducted cost reduction initiatives to reduce both labor and non-labor expenses.
  - A $114 million increase in demand side management, energy efficiency and vegetation management programs and other related expenses. All of these expenses are currently recovered dollar-for-dollar in rate recovery riders/trackers in Gross Margin.
  - A $54 million increase due to the write-off of APCo's Virginia share of the Mountaineer Carbon Capture and Storage Product Validation Facility as denied for recovery by the Virginia SCC.

  These increases were partially offset by:
  - An $89 million decrease in storm expenses.
- **Depreciation and Amortization** increased $37 million primarily due to new environmental improvements placed in service at APCo, CSPCo and OPCo and placing the Stall Unit in service at SWEPCo partially offset by lower depreciation in Arkansas and Texas as a result of SWEPCo's recent base rate orders.
- **Taxes Other Than Income Taxes** increased $60 million primarily due to the employer portion of payroll taxes incurred related to the cost reduction initiatives and higher franchise and property taxes.
- **Carrying Costs Income** increased $23 million primarily due to environmental construction in Virginia and a higher under-recovered fuel balance for OPCo.
- **Interest Expense** increased $26 million primarily due to an increase in long-term debt and a decrease in the debt component of AFUDC due to completed environmental improvements at APCo, CSPCo and OPCo.
- **Income Tax Expense** increased $97 million primarily due to the regulatory accounting treatment of state income taxes, other book/tax differences which are accounted for on a flow-through basis and the tax treatment associated with the future reimbursement of Medicare Part D prescription drug benefits, partially offset by a decrease in pretax book income.

2009 Compared to 2008

Reconciliation of Year Ended December 31, 2008 to Year Ended December 31, 2009
Income from Utility Operations Before Discontinued Operations and Extraordinary Loss
(in millions)

Year Ended December 31, 2008	$	1,123
Changes in Gross Margin:		
Retail Margins		549
Off-system Sales		(333)
Transmission Revenues		25
Other Revenues		198
Total Change in Gross Margin		439
Total Expenses and Other:		
Other Operation and Maintenance		(46)
Depreciation and Amortization		(111)
Taxes Other Than Income Taxes		(2)
Interest and Investment Income		(38)
Carrying Costs Income		(36)
Allowance for Equity Funds Used During Construction		37
Interest Expense		(1)
Equity Earnings of Unconsolidated Subsidiaries		2
Total Expenses and Other		(195)
Income Tax Expense		(38)
Year Ended December 31, 2009	$	1,329

The major components of the increase in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased power were as follows:

- **Retail Margins** increased $549 million primarily due to the following:
  - Successful rate proceedings in our service territories which include:
    - A $187 million increase related to the PUCO's approval of our Ohio ESPs.
    - A $170 million increase related to base rates and recovery of E&R costs in Virginia and construction financing costs in West Virginia.
    - A $75 million net rate increase for PSO.
    - A $42 million net rate increase for I&M.
    - A $50 million net rate increase in our other jurisdictions.
  - A $201 million increase in fuel margins in Ohio primarily due to the deferral of fuel costs by CSPCo and OPCo in 2009. The PUCO's March 2009 approval of CSPCo's and OPCo's ESPs allows for the deferral of fuel and related costs related to the ESP period.
  - A $102 million increase due to the December 2008 provision for refund of off-system sales margins as ordered by the FERC related to the SIA.
  - A $68 million increase due to lower PJM and other costs as the result of lower generation sales.

  These increases were partially offset by:
  - A $214 million decrease in margins from industrial sales due to reduced operating levels and suspended operations by certain large industrial customers in our service territories.
  - A $78 million decrease in fuel margins due to higher fuel and purchased power costs related to the Cook Plant Unit 1 shutdown. This decrease in fuel margins was offset by a corresponding increase in Other Revenues as discussed below.
  - A $52 million decrease in weather-related usage primarily due to a 14% decrease in cooling degree days in our eastern service territory.
  - A $29 million decrease related to favorable coal contract amendments in 2008.

- **Margins from Off-system Sales** decreased $333 million primarily due to lower physical sales volumes and lower margins in our eastern service territory reflecting lower market prices, partially offset by higher trading and marketing margins.
- **Transmission Revenues** increased $25 million primarily due to increased rates in the ERCOT and SPP regions.
- **Other Revenues** increased $198 million primarily due to the Cook Plant accidental outage insurance proceeds of $185 million which ended when Unit 1 returned to service in December 2009. I&M reduced customer bills by approximately $78 million in 2009 for the cost of replacement power resulting during the outage period. This decrease in insurance proceeds was offset by a corresponding increase in Retail Margins as discussed above.

Total Expenses and Other and Income Tax Expense changed between years as follows:

- **Other Operation and Maintenance** expenses increased $46 million primarily due to the following:
  - The 2008 deferral of $74 million of previously expensed Oklahoma ice storm costs resulting from an OCC order approving recovery of January and December 2007 ice storm expenses.
  - A $64 million increase in administrative and general expenses primarily for employee benefits.
  - A $48 million increase in storm restoration expenses due to the December 2009 winter storm in Tennessee, Virginia and West Virginia.
  - A $32 million increase in demand side management, energy efficiency and vegetation management programs.
  - A $29 million increase in recoverable transmission service expenses.
  - A $14 million increase due to the completion of reliability deferrals in Virginia in December 2008 and the decrease of environmental deferrals in Virginia in 2009.

  These increases were partially offset by:
  - A $67 million decrease in distribution and customer account expenses.
  - A $51 million decrease in transmission expenses related to cost recovery rider amortization in Ohio and rate adjustment clause deferrals in Virginia.
  - A $43 million decrease in other operating expenses including lower charitable contributions.
  - A $39 million decrease in RTO fees, forestry and other transmission expenses.
  - A $15 million decrease in plant outages and other plant operating and maintenance expenses, including lower removal costs.
- **Depreciation and Amortization** increased $111 million primarily due to higher depreciable property balances as the result of environmental improvements placed in service at OPCo and various other property additions and higher depreciation rates for OPCo related to shortened depreciable lives for certain generating facilities.
- **Interest and Investment Income** decreased $38 million primarily due to lower interest income related to federal income tax refunds filed with the IRS and the recognition of other-than-temporary losses related to equity investments held by our protected cell of EIS in 2009.
- **Carrying Costs Income** decreased $36 million primarily due to the completion of reliability deferrals in Virginia in December 2008 and the decrease of environmental deferrals in Virginia in 2009.
- **Allowance for Equity Funds Used During Construction** increased $37 million as a result of construction at SWEPCo's Turk Plant and Stall Unit and the reapplication of "Regulated Operations" accounting guidance for the generation portion of SWEPCo's Texas retail jurisdiction effective the second quarter of 2009.
- **Interest Expense** increased $1 million primarily due to a $52 million increase in interest expense related to increased long-term debt borrowings partially offset by interest expense of $47 million recorded in 2008 related to the 2008 SIA adjustment for off-system sales margins in accordance with the FERC's 2008 order.
- **Income Tax Expense** increased $38 million primarily due to an increase in pretax book income offset by the regulatory accounting treatment of state income taxes and other book/tax differences which are accounted for on a flow-through basis.

AEP RIVER OPERATIONS

2010 Compared to 2009

Income Before Discontinued Operations and Extraordinary Loss from our AEP River Operations segment decreased from $47 million in 2009 to $37 million in 2010 primarily due to expenses related to cost reduction initiatives, increased interest expense on new equipment financing, a property casualty loss in 2010 and a gain on the sale of two older towboats in 2009.

2009 Compared to 2008

Income Before Discontinued Operations and Extraordinary Loss from our AEP River Operations segment decreased from $55 million in 2008 to $47 million in 2009 primarily due to lower revenues as a result of a weak import market.

GENERATION AND MARKETING

2010 Compared to 2009

Income Before Discontinued Operations and Extraordinary Loss from our Generation and Marketing segment decreased from $41 million in 2009 to $25 million in 2010 primarily due to reduced inception gains from ERCOT marketing activities, reduced plant performance due to lower power prices in ERCOT, partially offset by positive hedging activities on our generation assets and increased income from our wind farm operations.

2009 Compared to 2008

Income Before Discontinued Operations and Extraordinary Loss from our Generation and Marketing segment decreased from $65 million in 2008 to $41 million in 2009 primarily due to lower gross margins at the Oklaunion Generating Station as a result of lower power prices in ERCOT and decreased generation from our wind farm operations.

ALL OTHER

2010 Compared to 2009

Income Before Discontinued Operations and Extraordinary Loss from All Other increased from a loss of $47 million in 2009 to a loss of $45 million in 2010 primarily due to gains on the sale of our remaining shares of Intercontinental Exchange, Inc. (ICE) and a decrease in various parent related expenses partially offset by a contribution to AEP's charitable foundation and losses on the sales of assets.

2009 Compared to 2008

Income Before Discontinued Operations and Extraordinary Loss from All Other decreased from income of $133 million in 2008 to a loss of $47 million in 2009. In 2008, we had after-tax income of $164 million from a litigation settlement of a purchase power and sale agreement with TEM.

AEP SYSTEM INCOME TAXES

2010 Compared to 2009

Income Tax Expense increased $68 million in comparison to 2009 primarily due to the regulatory accounting treatment of state income taxes, other book/tax differences which are accounted for on a flow-through basis and the tax treatment associated with the future reimbursement of Medicare Part D retiree prescription drug benefits, offset in part by a decrease in pretax book income.

2009 Compared to 2008

Income Tax Expense decreased $67 million in comparison to 2008 primarily due to a decrease in pretax book income and the regulatory accounting treatment of state income taxes and other book/tax differences which are accounted for on a flow-through basis.

FINANCIAL CONDITION

We measure our financial condition by the strength of our balance sheet and the liquidity provided by our cash flows. Target debt to equity ratios are usually maintained for each subsidiary and often credit arrangements contain ratios as covenants that must be met for borrowing to continue.

LIQUIDITY AND CAPITAL RESOURCES

Debt and Equity Capitalization

	December 31,			
	2010		2009	
	(dollars in millions)			
Long-term Debt, including amounts due within one year	$ 16,811	52.8 %	$ 17,498	56.8 %
Short-term Debt	1,346	4.2	126	0.4
Total Debt	18,157	57.0	17,624	57.2
Preferred Stock of Subsidiaries	60	0.2	61	0.2
AEP Common Equity	13,622	42.8	13,140	42.6
Total Debt and Equity Capitalization	$ 31,839	100.0 %	$ 30,825	100.0 %

Our ratio of debt-to-total capital decreased from 57.2% in 2009 to 57% in 2010 primarily due to an increase in common equity.

Liquidity

Liquidity, or access to cash, is an important factor in determining our financial stability. We believe we have adequate liquidity under our existing credit facilities. At December 31, 2010, we had $3.4 billion in aggregate credit facility commitments to support our operations. Additional liquidity is available from cash from operations and a sale of receivables agreement. We are committed to maintaining adequate liquidity. We generally use short-term borrowings to fund working capital needs, property acquisitions and construction until long-term funding is arranged. Sources of long-term funding include issuance of long-term debt, sale-leaseback or leasing agreements or common stock.

Credit Facilities

We manage our liquidity by maintaining adequate external financing commitments. At December 31, 2010, our available liquidity was approximately $2.5 billion as illustrated in the table below:

	Amount (in millions)	Maturity
Commercial Paper Backup:		
Revolving Credit Facility	$ 1,454	April 2012
Revolving Credit Facility	1,500	June 2013
Revolving Credit Facility	478	April 2011
Total	3,432	
Cash and Cash Equivalents	294	
Total Liquidity Sources	3,726	
Less: AEP Commercial Paper Outstanding	650	
Letters of Credit Issued	601	
Net Available Liquidity	$ 2,475	

We have credit facilities totaling $3.4 billion, of which two $1.5 billion credit facilities support our commercial paper program. In June 2010, we terminated one of the $1.5 billion credit facilities that was scheduled to mature in March 2011 and replaced it with a new $1.5 billion credit facility which matures in 2013. These credit facilities also allow us to issue letters of credit in an amount up to $1.35 billion. In June 2010, we also reduced the credit facility that matures in April 2011 from $627 million to $478 million. This facility is fully utilized for letters of credit providing liquidity support for Pollution Control Bonds. In March 2011, we intend to replace the revolving credit facility of $478 million with bilateral letters of credit or refinance the bonds. We may redeem some portion of the Pollution Control Bonds supported by the facility.

We use our commercial paper program to meet the short-term borrowing needs of the subsidiaries. The program is used to fund both a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds the majority of the nonutility subsidiaries. In addition, the program also funds, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either money pool for regulatory or operational reasons. The maximum amount of commercial paper outstanding during 2010 was $868 million. The weighted-average interest rate for our commercial paper during 2010 was 0.43%.

Securitized Accounts Receivables

In 2010, we renewed our receivables securitization agreement. The agreement provides a commitment of $750 million from bank conduits to purchase receivables. A commitment of $375 million expires in July 2011 and the remaining commitment of $375 million expires in July 2013. We intend to extend or replace the agreement expiring in July 2011 on or before its maturity.

Debt Covenants and Borrowing Limitations

Our revolving credit agreements contain certain covenants and require us to maintain our percentage of debt to total capitalization at a level that does not exceed 67.5%. The method for calculating outstanding debt and capitalization is contractually defined in our revolving credit agreements. At December 31, 2010, this contractually-defined percentage was 53.3%. Nonperformance under these covenants could result in an event of default under these credit agreements. At December 31, 2010, we complied with all of the covenants contained in these credit agreements. In addition, the acceleration of our payment obligations, or the obligations of certain of our major subsidiaries, prior to maturity under any other agreement or instrument relating to debt outstanding in excess of $50 million, would cause an event of default under these credit agreements and in a majority of our non-exchange traded commodity contracts which would permit the lenders and counterparties to declare the outstanding amounts payable. However, a default under our non-exchange traded commodity contracts does not cause an event of default under our revolving credit agreements.

The revolving credit facilities do not permit the lenders to refuse a draw on any facility if a material adverse change occurs.

Utility Money Pool borrowings and external borrowings may not exceed amounts authorized by regulatory orders. At December 31, 2010, we had not exceeded those authorized limits.

Dividend Policy and Restrictions

The Board of Directors declared a quarterly dividend of $0.46 per share in January 2011. Future dividends may vary depending upon our profit levels, operating cash flow levels and capital requirements, as well as financial and other business conditions existing at the time. Our income derives from our common stock equity in the earnings of our utility subsidiaries. Various financing arrangements, charter provisions and regulatory requirements may impose certain restrictions on the ability of our utility subsidiaries to transfer funds to us in the form of dividends.

We have the option to defer interest payments on the AEP Junior Subordinated Debentures for one or more periods of up to 10 consecutive years per period. During any period in which we defer interest payments, we may not declare or pay any dividends or distributions on, or redeem, repurchase or acquire, our common stock.

We do not believe restrictions related to our various financing arrangements, charter provisions and regulatory requirements will have any significant impact on Parent's ability to access cash to meet the payment of dividends on its common stock.

Credit Ratings

We do not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit downgrade, but our access to the commercial paper market may depend on our credit ratings. In addition, downgrades in our credit ratings by one of the rating agencies could increase our borrowing costs. Counterparty concerns about the credit quality of AEP or its utility subsidiaries could subject us to additional collateral demands under adequate assurance clauses under our derivative and non-derivative energy contracts.

CASH FLOW

Managing our cash flows is a major factor in maintaining our liquidity strength.

	Years Ended December 31,		
	2010	2009	2008
		(in millions)	
Cash and Cash Equivalents at Beginning of Period	$ 490	$ 411	$ 178
Net Cash Flows from Operating Activities	2,662	2,475	2,581
Net Cash Flows Used for Investing Activities	(2,523)	(2,916)	(4,027)
Net Cash Flows from (Used for) Financing Activities	(335)	520	1,679
Net Increase (Decrease) in Cash and Cash Equivalents	(196)	79	233
Cash and Cash Equivalents at End of Period	$ 294	$ 490	$ 411

Cash from operations and short-term borrowings provides working capital and allows us to meet other short-term cash needs.

Operating Activities

	Years Ended December 31,		
	2010	2009	2008
		(in millions)	
Net Income	$ 1,218	$ 1,365	$ 1,388
Depreciation and Amortization	1,641	1,597	1,483
Other	(197)	(487)	(290)
Net Cash Flows from Operating Activities	$ 2,662	$ 2,475	$ 2,581

Net Cash Flows from Operating Activities were $2.7 billion in 2010 consisting primarily of Net Income of $1.2 billion and $1.6 billion of noncash Depreciation and Amortization. Other changes represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. Other includes a $656 million increase in securitized receivables under the application of new accounting guidance for "Transfers and Servicing" related to our sale of receivables agreement. Significant changes in other items include an increase in under-recovered fuel primarily due to the deferral of fuel under the FAC in Ohio and higher fuel costs in Oklahoma, accrued tax benefits and the favorable impact of a decrease in fuel inventory. Deferred Income Taxes increased primarily due to a change in tax versus book temporary differences from operations. Accrued Taxes, Net increased primarily as a result of the receipt of a federal income tax refund of $419 million related to a net operating loss in 2009 that was carried back to 2007 and 2008. We also contributed $500 million to our qualified pension trust in 2010.

Net Cash Flows from Operating Activities were $2.5 billion in 2009 consisting primarily of Net Income of $1.4 billion and $1.6 billion of noncash Depreciation and Amortization. Other represents items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. Significant changes in other items include the negative impact on cash of an increase in coal inventory reflecting decreased customer demand for electricity, an increase in under-recovered fuel primarily in Ohio and West Virginia and an increase in accrued tax benefits resulting from a net income tax operating loss in 2009. Deferred Income Taxes increased primarily due to the American Recovery and Reinvestment Act of 2009 extending bonus depreciation provisions, a one-time change in tax accounting method and an increase in tax versus book temporary differences from operations.

Net Cash Flows from Operating Activities were $2.6 billion in 2008 consisting primarily of Net Income of $1.4 billion and $1.5 billion of noncash Depreciation and Amortization. Other changes represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. Net Cash Flows from Operating Activities increased in 2008 due to the TEM settlement. Under-recovered fuel costs and fuel, materials and supplies inventories increased working capital requirements due to the higher cost of coal and natural gas. Deferred Income Taxes increased primarily due to the enactment of the Economic Stimulus Act which enhanced expensing provisions for certain assets placed in service in 2008 and provided for a 50% bonus depreciation provision for certain assets placed in service in 2008.

Investing Activities

	Years Ended December 31,		
	2010	2009	2008
		(in millions)	
Construction Expenditures	$ (2,345)	$ (2,792)	$ (3,800)
Acquisitions of Nuclear Fuel	(91)	(169)	(192)
Acquisitions of Assets	(155)	(104)	(160)
Proceeds from Sales of Assets	187	278	90
Other	(119)	(129)	35
Net Cash Flows Used for Investing Activities	$ (2,523)	$ (2,916)	$ (4,027)

Net Cash Flows Used for Investing Activities were $2.5 billion in 2010 primarily due to Construction Expenditures for environmental, new generation, distribution and transmission investments. Proceeds from Sales of Assets in 2010 include $139 million for sales of Texas transmission assets to ETT.

Net Cash Flows Used for Investing Activities were $2.9 billion in 2009 primarily due to Construction Expenditures for our new generation, environmental and distribution investments. Proceeds from Sales of Assets in 2009 includes $104 million relating to the sale of a portion of Turk Plant to joint owners as planned and $95 million for sales of Texas transmission assets to ETT.

Net Cash Flows Used for Investing Activities were $4 billion in 2008 primarily due to Construction Expenditures for distribution, environmental and new generation investments.

Financing Activities

	Years Ended December 31,		
	2010	2009	2008
		(in millions)	
Issuance of Common Stock, Net	$ 93	$ 1,728	$ 159
Issuance/Retirement of Debt, Net	497	(360)	2,266
Dividends Paid on Common Stock	(824)	(758)	(666)
Other	(101)	(90)	(80)
Net Cash Flows from (Used for) Financing Activities	$ (335)	$ 520	$ 1,679

Net Cash Flows Used for Financing Activities were $335 million in 2010. Our net debt issuances were $497 million. The net issuances included issuances of $952 million of notes and $326 million of pollution control bonds, a $531 million increase in commercial paper outstanding and retirements of $1.6 billion of notes, $148 million of securitization bonds and $222 million of pollution control bonds. Our short-term debt securitized by receivables increased $656 million under the application of new accounting guidance for "Transfers and Servicing" related to our sale of receivables agreement. We paid common stock dividends of $824 million.

Net Cash Flows from Financing Activities were $520 million in 2009. Issuance of Common Stock, Net of $1.7 billion is comprised of our issuance of 69 million shares of common stock with net proceeds of $1.64 billion and additional shares through our dividend reinvestment, employee savings and incentive programs. Our net debt retirements were $360 million. The net retirements included the repayment of $2 billion outstanding under our credit facilities and retirement of $816 million of long-term debt and issuances of $1.9 billion of senior unsecured and debt notes and $431 million of pollution control bonds. We paid common stock dividends of $758 million.

Net Cash Flows from Financing Activities were $1.7 billion in 2008 primarily due to the borrowing under our credit facility to provide liquidity during the 2008 credit market. We paid common stock dividends of $666 million.

The following financing activities occurred during 2010:

AEP Common Stock:

- During 2010, we issued 3 million shares of common stock under our incentive compensation, employee savings and dividend reinvestment plans and received net proceeds of $93 million.

Debt:

- During 2010, we issued approximately $1.3 billion of long-term debt, including $650 million of senior notes at interest rates ranging from 3.4% to 6.2%, $150 million of senior notes at a variable interest rate, $326 million of pollution control revenue bonds at interest rates ranging from 2.875% to 5.375%, $84 million of notes at a 4% interest rate and $68 million of notes at a variable interest rate. The proceeds from these issuances were used to fund long-term debt maturities and our construction programs.
- During 2010, we entered into $1 billion of interest rate derivatives and settled $172 million of such transactions. The settlements resulted in net cash payments of $6 million. As of December 31, 2010, we had in place $907 million of notional interest rate derivatives designated as cash flow and fair value hedges.

In 2011:

- In January 2011, TCC retired $92 million of its outstanding Securitization Bonds.
- In January 2011, PSO issued $250 million of 4.4% Senior Unsecured Notes due 2021.
- In January 2011, PSO gave notice to retire $200 million of 6% Senior Unsecured Notes due in 2032 on February 28, 2011.
- In February 2011, APCo issued $65 million of 2% Pollution Control Bonds due 2041 with a 2012 mandatory put date.
- We expect to refinance approximately $1 billion of the $1.3 billion of long-term debt that will mature in 2011.

BUDGETED CONSTRUCTION EXPENDITURES

We forecast approximately $2.5 billion and $2.6 billion of construction expenditures excluding AFUDC and capitalized interest for 2011 and 2012, respectively. For 2012 through 2014, we forecast annual construction expenditures to average between $2.6 billion and $3.1 billion. The projected increases are generally the result of required environmental investment to comply with Federal EPA rules and additional transmission spending. Estimated construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, weather, legal reviews and the ability to access capital. We expect to fund these construction expenditures through cash flows from operations and financing activities. Generally, the subsidiaries use cash or short-term borrowings under the money pool to fund these expenditures until long-term funding is arranged. The estimated expenditures include amounts for completion of the Turk and Dresden Plants. Both plants are scheduled for completion in 2012. We resumed work on Dresden in the first quarter of 2011. The 2011 estimated construction expenditures include generation, transmission and distribution related investments, as well as expenditures for compliance with environmental regulations as follows:

	Budgeted Construction Expenditures (in millions)
Environmental	$ 223
Generation	813
Transmission	594
Distribution	776
Other	100
Total	$ 2,506

OFF-BALANCE SHEET ARRANGEMENTS

In prior periods, under a limited set of circumstances, we entered into off-balance sheet arrangements for various reasons including accelerating cash collections, reducing operational expenses and spreading risk of loss to third parties. Our current guidelines restrict the use of off-balance sheet financing entities or structures to traditional operating lease arrangements and transfers of customer accounts receivable that we enter in the normal course of business. The following identifies significant off-balance sheet arrangements:

AEP Credit

AEP Credit has a receivables securitization agreement with bank conduits. Under this agreement, AEP Credit securitizes an interest in a portion of the receivables it acquires from affiliated utilities with the bank conduits and receives cash. Effective January 1, 2010, we record the receivables and debt related to AEP Credit on our Consolidated Balance Sheet.

At December 31, 2009, AEP Credit had $631 million of securitized receivables outstanding. See "ASU 2009-16 'Transfers and Servicing' (ASU 2009-16)" section of Note 2.

Rockport Plant Unit 2

AEGCo and I&M entered into a sale and leaseback transaction in 1989 with Wilmington Trust Company (Owner Trustee), an unrelated unconsolidated trustee for Rockport Plant Unit 2 (the Plant). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and certain institutional investors. The future minimum lease payments for each company are $887 million as of December 31, 2010.

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the Plant and leases it to AEGCo and I&M. Our subsidiaries account for the lease as an operating lease with the future payment obligations included in Note 13. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the Plant. We, as well as our subsidiaries, have no ownership interest in the Owner Trustee and do not guarantee its debt.

Railcars

In June 2003, we entered into an agreement with BTM Capital Corporation, as lessor, to lease 875 coal-transporting aluminum railcars. The initial lease term was five years with three consecutive five-year renewal periods for a maximum lease term of twenty years. We intend to maintain the lease for the full lease term of twenty years via the renewal options. The lease is accounted for as an operating lease. The future minimum lease obligation is $36 million for the remaining railcars as of December 31, 2010. Under a return-and-sale option, the lessor is guaranteed that the sale proceeds will equal at least a specified lessee obligation amount which declines with each five year renewal. At December 31, 2010, the maximum potential loss was approximately $25 million ($17 million, net of tax) assuming the fair value of the equipment is zero at the end of the current five-year lease term. However, we believe that the fair value would produce a sufficient sales price to avoid any loss. We have other railcar lease arrangements that do not utilize this type of financing structure.

CONTRACTUAL OBLIGATION INFORMATION

Our contractual cash obligations include amounts reported on the Consolidated Balance Sheets and other obligations disclosed in our footnotes. The following table summarizes our contractual cash obligations at December 31, 2010:

Payments Due by Period

Contractual Cash Obligations	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
			(in millions)		
Short-term Debt (a)	$ 1,346	$ -	$ -	$ -	$ 1,346
Interest on Fixed Rate Portion of Long-term Debt (b)	909	1,709	1,467	7,778	11,863
Fixed Rate Portion of Long-term Debt (c)	752	2,009	2,431	10,947	16,139
Variable Rate Portion of Long-term Debt (d)	557	150	-	-	707
Capital Lease Obligations (e)	100	159	106	286	651
Noncancelable Operating Leases (e)	306	547	467	1,349	2,669
Fuel Purchase Contracts (f)	2,810	3,974	2,543	3,718	13,045
Energy and Capacity Purchase Contracts (g)	69	199	204	1,101	1,573
Construction Contracts for Capital Assets (h)	1,031	1,407	1,636	3,143	7,217
Total	$ 7,880	$ 10,154	$ 8,854	$ 28,322	$ 55,210

(a) Represents principal only excluding interest.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2010 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(c) See "Long-term Debt" section of Note 14. Represents principal only excluding interest.
(d) See "Long-term Debt" section of Note 14. Represents principal only excluding interest. Variable rate debt had interest rates that ranged between 0.29% and 1.31% at December 31, 2010.
(e) See Note 13.
(f) Represents contractual obligations to purchase coal, natural gas, uranium and other consumables as fuel for electric generation along with related transportation of the fuel.
(g) Represents contractual obligations for energy and capacity purchase contracts.
(h) Represents only capital assets for which we have signed contracts. Actual payments are dependent upon and may vary significantly based upon the decision to build, regulatory approval schedules, timing and escalation of project costs.

Our $119 million liability related to uncertainty in Income Taxes is not included above because we cannot reasonably estimate the cash flows by period.

Our pension funding requirements are not included in the above table. As of December 31, 2010, we expect to make contributions to our pension plans totaling $158 million in 2011. Estimated contributions of $158 million in 2012 and $158 million in 2013 may vary significantly based on market returns, changes in actuarial assumptions and other factors. Based upon the benefit obligation and fair value of assets available to pay pension benefits, our pension plans were 80.3% funded as of December 31, 2010.

In addition to the amounts disclosed in the contractual cash obligations table above, we make additional commitments in the normal course of business. These commitments include standby letters of credit, guarantees for the payment of obligation performance bonds and other commitments. At December 31, 2010, our commitments outstanding under these agreements are summarized in the table below:

Amount of Commitment Expiration Per Period

Other Commercial Commitments	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
			(in millions)		
Standby Letters of Credit (a)	$ 601	$ -	$ -	$ -	$ 601
Guarantees of the Performance of Outside Parties (b)	-	-	-	65	65
Guarantees of Our Performance (c)	1,457	18	20	41	1,536
Total Commercial Commitments	$ 2,058	$ 18	$ 20	$ 106	$ 2,202

(a) We enter into standby letters of credit (LOCs) with third parties. These LOCs cover items such as gas and electricity risk management contracts, construction contracts, insurance programs, security deposits, debt service reserves and variable rate Pollution Control Bonds. AEP, on behalf of our subsidiaries, and/or the subsidiaries issued all of these LOCs in the ordinary course of business. There is no collateral held in relation to any guarantees in excess of our ownership percentages. In the event any LOC is drawn, there is no recourse to third parties. The maximum future payments of these LOCs are $601 million with maturities ranging from January 2011 to November 2011. See "Letters of Credit" section of Note 6.
(b) See "Guarantees of Third-Party Obligations" section of Note 6.
(c) We issued performance guarantees and indemnifications for energy trading and various sale agreements.

SIGNIFICANT TAX LEGISLATION

The American Recovery and Reinvestment Tax Act of 2009 provided for several new grant programs, expanded tax credits and extended the 50% bonus depreciation provision enacted in the Economic Stimulus Act of 2008. The Small Business Jobs Act, enacted in September 2010, included a one-year extension of the 50% bonus depreciation provision. The Tax Relief, Unemployment Insurance Reauthorization and the Job Creation Act of 2010 extended the life of research and development, employment and several energy tax credits originally scheduled to expire at the end of 2010. In addition, this act extended the time for claiming bonus depreciation and increased the deduction to 100% starting in September 2010 through 2011 and decreasing the deduction to 50% for 2012.

These enacted provisions will have no material impact on net income or financial condition but will have a favorable impact on cash flows in 2011 and are expected to result in material future cash flow benefits.

TRANSMISSION INITIATIVES

AEP Transmission Company, LLC (Utility Operations segment)

In 2006, we formed AEP Transmission Company, LLC (AEP Transco). In 2009, AEP Transco formed seven wholly-owned transmission companies. Upon approval of FERC interim rates, the transmission companies began recognizing revenues in July 2010 for their respective investments in PJM and SPP. The transmission companies have been established in Ohio, Oklahoma and Michigan. Applications for establishment of AEP Kentucky Transmission Company, Inc. and AEP West Virginia Transmission Company, Inc. have been filed with the KPSC and the WVPSC, respectively, and are pending approval. Other filings with commissions will be made in 2011. These seven companies consist of:

AEP East Transmission companies:
- AEP Appalachian Transmission Company, Inc. (covering Virginia)
- AEP Indiana Michigan Transmission Company, Inc.
- AEP Kentucky Transmission Company, Inc.
- AEP Ohio Transmission Company, Inc.
- AEP West Virginia Transmission Company, Inc.

AEP West Transmission companies:
- AEP Oklahoma Transmission Company, Inc.
- AEP Southwestern Transmission Company, Inc. (covering Arkansas and Louisiana)

AEPSC and other AEP subsidiaries provide services to the transmission companies through service agreements. Therefore, the transmission companies do not have any employees.

AEP Transco owns all of the transmission companies' equity. The transmission companies do not have outstanding debt and have not received capital contributions. All of the transmission companies' capital needs are provided by Parent and AEP Transco. For the transmission companies listed above, we forecast approximately $160 million of construction expenditures for 2011.

Joint Venture Initiatives (Utility Operations segment)

We are currently participating in the following joint venture initiatives:

Project Name	Location	Projected Completion Date	Owners (Ownership %)	Total Estimated Project Costs at Completion	AEP's Equity Method Investment at December 31, 2010	Approved Return on Equity
				(in thousands)		
ETT	Texas (ERCOT)	2017	MEHC Texas Transco, LLC (50%) AEP (50%)	$ 3,100,000 (a)	$ 110,323	9.96 %
PATH (b)	West Virginia	2015 (c)	Allegheny Energy (50%) AEP (50%)	2,100,000 (d)	23,621	14.3 % (e)
Prairie Wind	Kansas	2014	Westar Energy (50%) ETA (50%) (f)	225,000	784	12.8 %
Pioneer	Indiana	2016	Duke Energy (50%) AEP (50%)	1,000,000	-	12.54 %

(a) In addition to ETT's current total estimated project costs of $3.1 billion, ETT plans to invest in additional transmission projects in ERCOT over the next several years. Future projects will be evaluated on a case-by-case basis.
(b) In September 2007, AEP Transmission Holding Company, LLC and AET PATH Company, LLC, a subsidiary of Allegheny Energy, Inc., formed a joint venture by creating Potomac-Appalachian Transmission Highline, LLC (PATH) and its subsidiaries. The PATH subsidiaries will operate as transmission utilities owning certain electric transmission assets within PJM.
(c) PJM has directed the construction of the PATH Project and placement of the project into service by June 2015, at the latest.
(d) PATH consists of the "West Virginia Series," which is owned equally by subsidiaries of Allegheny Energy Inc. and AEP, and the "Allegheny Series" which is wholly-owned by a subsidiary of Allegheny Energy Inc. The total project is estimated to cost approximately $2.1 billion. Our estimated share of the project cost is approximately $700 million. In February 2011, the "Ohio Series" was dissolved, which was owned equally by subsidiaries of Allegheny Energy Inc. and AEP.
(e) An October 2010 FERC order set the 14.3% return on equity for hearing.
(f) Electric Transmission America, LLC (ETA) is a 50/50 joint venture with MidAmerican Energy Holdings Company (MEHC) America Transco, LLC and AEP Transmission Holding Company, LLC. ETA will be utilized as a vehicle to invest in selected transmission projects located in North America, outside of ERCOT. AEP Transmission Holding Company, LLC owns 25% of Prairie Wind through its ownership interest in ETA.

For our joint ventures listed above, we forecast approximately $113 million of equity contributions in 2011 to support construction and other expenditures.

MINE SAFETY INFORMATION

The Federal Mine Safety and Health Act of 1977 (Mine Act) imposes stringent health and safety standards on various mining operations. The Mine Act and its related regulations affect numerous aspects of mining operations, including training of mine personnel, mining procedures, equipment used in mine emergency procedures, mine plans and other matters. SWEPCo, through its ownership of DHLC, CSPCo, through its ownership of Conesville Coal Preparation Company (CCPC), and OPCo, through its use of the Conner Run fly ash impoundment, are subject to the provisions of the Mine Act.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) requires companies that operate mines to include in their periodic reports filed with the SEC, certain mine safety information covered by the Mine Act. DHLC, CCPC and Conner Run received the following notices of violation and proposed assessments under the Mine Act for the quarter ended December 31, 2010:

	DHLC	CCPC	Conner Run
Number of Citations for Violations of Mandatory Health or Safety Standards under 104 *	1	-	-
Number of Orders Issued under 104(b) *	-	-	-
Number of Citations and Orders for Unwarrantable Failure to Comply with Mandatory Health or Safety Standards under 104(d) *	-	-	-
Number of Flagrant Violations under 110(b)(2) *	-	-	-
Number of Imminent Danger Orders Issued under 107(a) *	-	-	-
Total Dollar Value of Proposed Assessments	$ 1,026	$ -	$ -
Number of Mining-related Fatalities	-	-	-

* References to sections under the Mine Act

DHLC currently has two legal actions pending before the Mine Safety and Health Administration (MSHA) challenging four violations issued by MSHA following an employee fatality in March 2009.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES, NEW ACCOUNTING PRONOUNCEMENTS

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements in accordance with GAAP requires us to make estimates and assumptions that affect reported amounts and related disclosures, including amounts related to legal matters and contingencies. We consider an accounting estimate to be critical if:

- It requires assumptions to be made that were uncertain at the time the estimate was made; and
- Changes in the estimate or different estimates that could have been selected could have a material effect on our consolidated net income or financial condition.

We discuss the development and selection of critical accounting estimates as presented below with the Audit Committee of AEP's Board of Directors and the Audit Committee reviews the disclosure relating to them.

We believe that the current assumptions and other considerations used to estimate amounts reflected in our consolidated financial statements are appropriate. However, actual results can differ significantly from those estimates.

The sections that follow present information about our critical accounting estimates, as well as the effects of hypothetical changes in the material assumptions used to develop each estimate.

Regulatory Accounting

Nature of Estimates Required

Our consolidated financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated.

We recognize regulatory assets (deferred expenses to be recovered in the future) and regulatory liabilities (deferred future revenue reductions or refunds) for the economic effects of regulation. Specifically, we match the timing of our expense recognition with the recovery of such expense in regulated revenues. Likewise, we match income with the regulated revenues from our customers in the same accounting period. We also record liabilities for refunds, or probable refunds, to customers that have not been made.

Assumptions and Approach Used

When incurred costs are probable of recovery through regulated rates, we record them as regulatory assets on the balance sheet. We review the probability of recovery at each balance sheet date and whenever new events occur. Examples of new events include changes in the regulatory environment, issuance of a regulatory commission order or passage of new legislation. The assumptions and judgments used by regulatory authorities continue to have an impact on the recovery of costs, rate of return earned on invested capital and timing and amount of assets to be recovered through regulated rates. If recovery of a regulatory asset is no longer probable, we write off that regulatory asset as a charge against earnings. A write-off of regulatory assets may also reduce future cash flows since there will be no recovery through regulated rates.

Effect if Different Assumptions Used

A change in the above assumptions may result in a material impact on our net income. Refer to Note 5 for further detail related to regulatory assets and liabilities.

Revenue Recognition – Unbilled Revenues

Nature of Estimates Required

We record revenues when energy is delivered to the customer. The determination of sales to individual customers is based on the reading of their meters, which we perform on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue accrual is recorded. This estimate is reversed in the following month and actual revenue is recorded based on meter readings. In accordance with the applicable state commission regulatory treatment in Arkansas, Louisiana, Oklahoma and Texas, PSO and SWEPCo do not record the fuel portion of unbilled revenue.

The changes in unbilled electric utility revenues included in Revenue on our Consolidated Statements of Income were $46 million, $55 million and $72 million for the years ended December 31, 2010, 2009 and 2008, respectively. The increases in unbilled electric revenues are primarily due to rate increases and changes in weather. Accrued unbilled revenues for the Utility Operations segment were $549 million and $503 million as of December 31, 2010 and 2009, respectively.

Assumptions and Approach Used

For each operating company, we compute the monthly estimate for unbilled revenues as net generation less the current month's billed KWH plus the prior month's unbilled KWH. However, due to meter reading issues, meter drift and other anomalies, a separate monthly calculation limits the unbilled estimate within a range of values. This limiter calculation is derived from an allocation of billed KWH to the current month and previous month, on a cycle-by-cycle basis, and by dividing the current month aggregated result by the billed KWH. The limits are statistically set at one standard deviation from this percentage to determine the upper and lower limits of the range. The unbilled estimate is compared to the limiter calculation and adjusted for variances exceeding the upper and lower limits.

Effect if Different Assumptions Used

Significant fluctuations in energy demand for the unbilled period, weather, line losses or changes in the composition of customer classes could impact the accuracy of the unbilled revenue estimate. A 1% change in the limiter calculation when it is outside the range would increase or decrease unbilled revenues by 1% of the accrued unbilled revenues.

Accounting for Derivative Instruments

Nature of Estimates Required

We consider fair value techniques, valuation adjustments related to credit and liquidity and judgments related to the probability of forecasted transactions occurring within the specified time period to be critical accounting estimates. These estimates are considered significant because they are highly susceptible to change from period to period and are dependent on many subjective factors.

Assumptions and Approach Used

We measure the fair values of derivative instruments and hedge instruments accounted for using MTM accounting based on exchange prices and broker quotes. If a quoted market price is not available, we estimate the fair value based on the best market information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data and other assumptions. Fair value estimates, based upon the best market information available, involve uncertainties and matters of significant judgment. These uncertainties include projections of macroeconomic trends and future commodity prices, including supply and demand levels and future price volatility.

We reduce fair values by estimated valuation adjustments for items such as discounting, liquidity and credit quality. We calculate liquidity adjustments by utilizing bid/ask spreads to estimate the potential fair value impact of liquidating open positions over a reasonable period of time. We calculate credit adjustments on our risk management contracts using estimated default probabilities and recovery rates relative to our counterparties or counterparties with similar credit profiles and contractual netting agreements.

With respect to hedge accounting, we assess hedge effectiveness and evaluate a forecasted transaction's probability of occurrence within the specified time period as provided in the original hedge documentation.

Effect if Different Assumptions Used

There is inherent risk in valuation modeling given the complexity and volatility of energy markets. Therefore, it is possible that results in future periods may be materially different as contracts settle.

The probability that hedged forecasted transactions will not occur by the end of the specified time period could change operating results by requiring amounts currently classified in Accumulated Other Comprehensive Income (Loss) to be classified into operating income.

For additional information regarding derivatives, hedging and fair value measurements, see Notes 10 and 11. See "Fair Value Measurements of Assets and Liabilities" section of Note 1 for fair value calculation policy.

Long-Lived Assets

Nature of Estimates Required

In accordance with the requirements of "Property, Plant and Equipment" accounting guidance, we evaluate long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of any such assets may not be recoverable or the assets meet the held for sale criteria. We utilize a group composite method of depreciation to estimate the useful lives of long-lived assets as approved by our regulators. The evaluations of long-lived held and used assets may result from abandonments, significant decreases in the market price of an asset, a significant adverse change in the extent or manner in which an asset is being used or in its physical condition, a significant adverse change in legal factors or in the business climate that could affect the value of an asset, as well as other economic or operations analyses. If the carrying amount is not recoverable, we record an impairment to the extent that the fair value of the asset is less than its book value. For assets held for sale, an impairment is recognized if the expected net sales price is less than its book value. For regulated assets, an impairment charge could be offset by the establishment of a regulatory asset if rate recovery is probable. For nonregulated assets, any impairment charge is recorded against earnings.

Assumptions and Approach Used

The fair value of an asset is the amount at which that asset could be bought or sold in a current transaction between willing parties other than in a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, we estimate fair value using various internal and external valuation methods including cash flow projections or other market indicators of fair value such as bids received, comparable sales or independent appraisals. We perform depreciation studies to determine composite depreciation rates and related lives which are subject to periodic review by state regulatory commissions. The fair value of the asset could be different using different estimates and assumptions in these valuation techniques.

Effect if Different Assumptions Used

In connection with the evaluation of long-lived assets in accordance with the requirements of "Property, Plant and Equipment" accounting guidance, the fair value of an asset can vary if different estimates and assumptions would have been used in our applied valuation techniques. The estimate for depreciation rates takes into account the history of interim capital replacements and the amount of salvage expected. In cases of impairment, we made our best estimate of fair value using valuation methods based on the most current information at that time. Fluctuations in realized sales proceeds versus the estimated fair value of the asset are generally due to a variety of factors including, but not limited to, differences in subsequent market conditions, the level of bidder interest, timing and terms of the transactions and our analysis of the benefits of the transaction.

Pension and Other Postretirement Benefits

We maintain a qualified, defined benefit pension plan (Qualified Plan), which covers substantially all nonunion and certain union employees, and unfunded, nonqualified supplemental plans (Nonqualified Plans) to provide benefits in excess of amounts permitted under the provisions of the tax law to be paid to participants in the Qualified Plan (collectively the Pension Plans). Additionally, we entered into individual employment contracts with certain current and retired executives that provide additional retirement benefits as a part of the Nonqualified Plans. We also sponsor other postretirement benefit plans to provide medical and life insurance benefits for retired employees (Postretirement Plans). The Pension Plans and Postretirement Plans are collectively the Plans.

For a discussion of investment strategy, investment limitations, target asset allocations and the classification of investments within the fair value hierarchy, see "Investments Held in Trust for Future Liabilities" and "Fair Value Measurements of Assets and Liabilities" sections of Note 1. See Note 8 for information regarding costs and assumptions for employee retirement and postretirement benefits.

The following table shows the net periodic cost of the Plans:

	Years Ended December 31,		
Net Periodic Benefit Cost	**2010**	**2009**	**2008**
		(in millions)	
Pension Plans	$ 141	$ 96	$ 51
Postretirement Plans	111	141	80

The net periodic benefit cost is calculated based upon a number of actuarial assumptions, including expected long-term rates of return on the Plans' assets. In developing the expected long-term rate of return assumption for 2011, we evaluated input from actuaries and investment consultants, including their reviews of asset class return expectations as well as long-term inflation assumptions. We also considered historical returns of the investment markets. We anticipate that the investment managers we employ for the Plans will invest the assets to generate future returns averaging 7.75% for the Qualified Plan and 7.5% for the Postretirement Plans.

The expected long-term rate of return on the Plans' assets is based on our targeted asset allocation and our expected investment returns for each investment category. Our assumptions are summarized in the following table:

	Pension Plans		Other Postretirement Benefit Plans	
	2011 Target Asset Allocation	Assumed/ Expected Long-Term Rate of Return	2011 Target Asset Allocation	Assumed/ Expected Long-Term Rate of Return
Equity	50 %	9.00 %	66 %	9.00 %
Real Estate	5 %	7.60 %	-%	- %
Fixed Income	39 %	5.75 %	32 %	5.75 %
Other Investments	5 %	10.50 %	-%	- %
Cash and Cash Equivalents	1 %	3.00 %	2 %	3.00 %
Total	100 %		100 %	

We regularly review the actual asset allocation and periodically rebalance the investments to our targeted allocation. We believe that 7.75% for the Pension Plan and 7.5% for the Postretirement Plans are reasonable long-term rates of return on the Plans' assets despite the recent market volatility. The Pension Plan's assets had an actual gain of 13.4% and 17.1% for the years ended December 31, 2010 and 2009, respectively. The Postretirement Plans' assets had an actual gain of 11.3% and 23.7% for the years ended December 31, 2010 and 2009, respectively. We will continue to evaluate the actuarial assumptions, including the expected rate of return, at least annually, and will adjust the assumptions as necessary.

We base our determination of pension expense or income on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the market-related value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded. As of December 31, 2010, we had cumulative losses of approximately $285 million that remain to be recognized in the calculation of the market-related value of assets. These unrecognized net actuarial losses will result in increases in the future pension costs depending on several factors, including whether such losses at each measurement date exceed the corridor in accordance with "Compensation – Retirement Benefits" accounting guidance.

The method used to determine the discount rate that we utilize for determining future obligations is a duration-based method in which a hypothetical portfolio of high quality corporate bonds similar to those included in the Moody's Aa bond index is constructed with a duration matching the benefit plan liability. The composite yield on the hypothetical bond portfolio is used as the discount rate for the plan. The discount rate at December 31, 2010 under this method was 5.05% for the Qualified Plan, 4.95% for the Nonqualified Plans and 5.25% for the Postretirement Plans. Due to the effect of the unrecognized actuarial losses and based on an expected rate of return on the Pension Plans' assets of 7.75%, discount rates of 5.05% and 4.95% and various other assumptions, we estimate that the pension costs for the Pension Plans will approximate $144 million, $166 million and $194 million in 2011, 2012 and 2013, respectively. Based on an expected rate of return on the Postretirement Plans' assets of 7.5%, a discount rate of 5.25% and various other assumptions, we estimate costs will approximate $82 million, $78 million and $74 million in 2011, 2012 and 2013, respectively. Future actual costs will depend on future investment performance, changes in future discount rates and various other factors related to the populations participating in the Plans. The actuarial assumptions used may differ materially from actual results. The effects of a 50 basis point change to selective actuarial assumptions are included in the "Effect if Different Assumptions Used" section below.

The value of the Pension Plan's assets increased to $3.9 billion at December 31, 2010 from $3.4 billion at December 31, 2009 primarily due to a $500 million contribution. During 2010, the Qualified Plan paid $465 million and the Nonqualified Plans paid $15 million in benefits to plan participants. The value of the Postretirement Plans' assets increased to $1.5 billion at December 31, 2010 from $1.3 billion at December 31, 2009 primarily due to investment gains and contributions. The Postretirement Plans paid $142 million in benefits to plan participants during 2010.

Nature of Estimates Required

We sponsor pension and other retirement and postretirement benefit plans in various forms covering all employees who meet eligibility requirements. We account for these benefits under "Compensation" and "Plan Accounting" accounting guidance. The measurement of our pension and postretirement benefit obligations, costs and liabilities is dependent on a variety of assumptions.

Assumptions and Approach Used

The critical assumptions used in developing the required estimates include the following key factors:

- Discount rate
- Rate of compensation increase
- Cash balance crediting rate
- Health care cost trend rate
- Expected return on plan assets

Other assumptions, such as retirement, mortality and turnover, are evaluated periodically and updated to reflect actual experience.

Effect if Different Assumptions Used

The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates, longer or shorter life spans of participants or higher or lower lump sum versus annuity payout elections by plan participants. These differences may result in a significant impact to the amount of pension and postretirement benefit expense recorded. If a 50 basis point change were to occur for the following assumptions, the approximate effect on the financial statements would be as follows:

	Pension Plans		Other Postretirement Benefit Plans	
	+0.5%	**-0.5%**	**+0.5%**	**-0.5%**
	(in millions)			
Effect on December 31, 2010 Benefit Obligations				
Discount Rate	$ (233)	$ 256	$ (132)	$ 147
Compensation Increase Rate	11	(10)	-	-
Cash Balance Crediting Rate	43	(38)	N/A	N/A
Health Care Cost Trend Rate	N/A	N/A	114	(101)
Effect on 2010 Periodic Cost				
Discount Rate	(20)	22	(12)	14
Compensation Increase Rate	4	(3)	1	(1)
Cash Balance Crediting Rate	10	(9)	N/A	N/A
Health Care Cost Trend Rate	N/A	N/A	18	(16)
Expected Return on Plan Assets	(20)	20	(6)	6

N/A Not Applicable

Nuclear Trust Funds

Nuclear decommissioning and spent nuclear fuel trust funds represent funds that regulatory commissions allow us to collect through rates to fund future decommissioning and spent nuclear fuel disposal liabilities. By rules or orders, the IURC, the MPSC and the FERC established investment limitations and general risk management guidelines.

We maintain trust funds for each regulatory jurisdiction. These funds are managed by external investment managers who must comply with the guidelines and rules of the applicable regulatory authorities. The trust assets are invested to optimize the net of tax earnings of the trust giving consideration to liquidity, risk, diversification and other prudent investment objectives. We record securities held in these trust funds as Spent Nuclear Fuel and

Decommissioning Trusts on our Consolidated Balance Sheets. We record these securities at fair value. We utilize our trustee's external pricing service in our estimate of the fair value of the underlying investments held in these trusts. Our investment managers review and validate the prices utilized by the trustee to determine fair value. We perform our own valuation testing to verify the fair values of the securities. We receive audit reports of our trustee's operating controls and valuation processes. See "Investments Held in Trust for Future Liabilities" section of Note 1 and "Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal" section of Note 11.

NEW ACCOUNTING PRONOUNCEMENTS

New Accounting Pronouncements Adopted During 2010

We adopted ASU 2009-16 "Transfers and Servicing" effective January 1, 2010. The adoption of this standard resulted in AEP Credit's transfers of receivables being accounted for as financings with the receivables and short-term debt recorded on our balance sheet.

We adopted the prospective provisions of ASU 2009-17 "Consolidations" effective January 1, 2010. We no longer consolidate DHLC effective with the adoption of this standard.

See Note 2 for further discussion of accounting pronouncements.

Future Accounting Changes

The FASB's standard-setting process is ongoing and until new standards have been finalized and issued, we cannot determine the impact on the reporting of our operations and financial position that may result from any such future changes. The FASB is currently working on several projects including revenue recognition, contingencies, financial instruments, emission allowances, fair value measurements, leases, insurance, hedge accounting, consolidation policy and discontinued operations. We also expect to see more FASB projects as a result of its desire to converge International Accounting Standards with GAAP. The ultimate pronouncements resulting from these and future projects could have an impact on our future net income and financial position.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET AND CREDIT RISK

Market Risks

Our Utility Operations segment is exposed to certain market risks as a major power producer and transacts in wholesale electricity, coal and emission allowance trading and marketing contracts. These risks include commodity price risk, interest rate risk and credit risk. In addition, we are exposed to foreign currency exchange risk because occasionally we procure various services and materials used in our energy business from foreign suppliers. These risks represent the risk of loss that may impact us due to changes in the underlying market prices or rates.

Our Generation and Marketing segment, operating primarily within ERCOT and to a lesser extent Ohio in PJM and MISO, primarily transacts in wholesale energy marketing contracts. This segment is exposed to certain market risks as a marketer of wholesale electricity. These risks include commodity price risk, interest rate risk and credit risk. These risks represent the risk of loss that may impact us due to changes in the underlying market prices or rates.

All Other includes natural gas operations which holds forward natural gas contracts that were not sold with the natural gas pipeline and storage assets. These contracts are financial derivatives, which gradually settle and completely expire in 2011. Our risk objective is to keep these positions generally risk neutral through maturity.

We employ risk management contracts including physical forward purchase and sale contracts and financial forward purchase and sale contracts. We engage in risk management of electricity, coal, natural gas and emission allowances and to a lesser degree other commodities associated with our energy business. As a result, we are subject to price risk. The amount of risk taken is determined by the commercial operations group in accordance with the market risk policy approved by the Finance Committee of our Board of Directors. Our market risk oversight staff independently monitors our risk policies, procedures and risk levels and provides members of the Commercial Operations Risk Committee (CORC) various daily, weekly and/or monthly reports regarding compliance with policies, limits and procedures. The CORC consists of our President, Chief Financial Officer, Senior Vice President of Commercial Operations and Chief Risk Officer. When commercial activities exceed predetermined limits, we modify the positions to reduce the risk to be within the limits unless specifically approved by the CORC.

The following table summarizes the reasons for changes in total mark-to-market (MTM) value as compared to December 31, 2009:

MTM Risk Management Contract Net Assets (Liabilities)
Year Ended December 31, 2010

	Utility Operations	Generation and Marketing	All Other	Total
		(in millions)		
Total MTM Risk Management Contract Net Assets (Liabilities) at December 31, 2009	$ 134	$ 147	$ (3)	$ 278
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(81)	(16)	5	(92)
Fair Value of New Contracts at Inception When Entered During the Period (a)	17	8	-	25
Net Option Premiums Received for Unexercised or Unexpired Option Contracts Entered During the Period	(1)	-	-	(1)
Changes in Fair Value Due to Valuation Methodology Changes on Forward Contracts (b)	(2)	(2)	-	(4)
Changes in Fair Value Due to Market Fluctuations During the Period (c)	6	3	-	9
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	18	-	-	18
Total MTM Risk Management Contract Net Assets at December 31, 2010	$ 91	$ 140	$ 2	233
Commodity Cash Flow Hedge Contracts				11
Interest Rate and Foreign Currency Cash Flow Hedge Contracts				21
Fair Value Hedge Contracts				6
Collateral Deposits				101
Total MTM Derivative Contract Net Assets at December 31, 2010				$ 372

(a) Reflects fair value on primarily long-term structured contracts which are typically with customers that seek fixed pricing to limit their risk against fluctuating energy prices. The contract prices are valued against market curves associated with the delivery location and delivery term. A significant portion of the total volumetric position has been economically hedged.
(b) Reflects changes in methodology in calculating the credit and discounting liability fair value adjustments.
(c) Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
(d) Relates to the net gains (losses) of those contracts that are not reflected on the Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets.

See Note 10 – Derivatives and Hedging and Note 11 – Fair Value Measurements for additional information related to our risk management contracts. The following tables and discussion provide information on our credit risk and market volatility risk.

Credit Risk

We limit credit risk in our wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. We use Moody's Investors Service, Standard & Poor's and current market-based qualitative and quantitative data as well as financial statements to assess the financial health of counterparties on an ongoing basis.

We have risk management contracts with numerous counterparties. Since open risk management contracts are valued based on changes in market prices of the related commodities, our exposures change daily. As of December 31, 2010, our credit exposure net of collateral to sub investment grade counterparties was approximately 5.3%, expressed in terms of net MTM assets, net receivables and the net open positions for contracts not subject to MTM (representing economic risk even though there may not be risk of accounting loss). As of December 31, 2010, the following table approximates our counterparty credit quality and exposure based on netting across commodities, instruments and legal entities where applicable:

Counterparty Credit Quality	Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Number of Counterparties >10% of Net Exposure	Net Exposure of Counterparties >10%
	(in millions, except number of counterparties)				
Investment Grade	$ 666	$ 19	$ 647	1	$ 189
Split Rating	2	-	2	1	2
Noninvestment Grade	4	3	1	2	1
No External Ratings:					
Internal Investment Grade	215	-	215	2	123
Internal Noninvestment Grade	59	11	48	1	32
Total as of December 31, 2010	$ 946	$ 33	$ 913	7	$ 347
Total as of December 31, 2009	$ 846	$ 58	$ 788	12	$ 317

Value at Risk (VaR) Associated with Risk Management Contracts

We use a risk measurement model, which calculates VaR, to measure our commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, as of December 31, 2010, a near term typical change in commodity prices is not expected to have a material effect on our net income, cash flows or financial condition.

The following table shows the end, high, average and low market risk as measured by VaR for the trading portfolio for the periods indicated:

VaR Model

Twelve Months Ended December 31, 2010				Twelve Months Ended December 31, 2009			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$-	$2	$1	$-	$1	$2	$1	$-

We back-test our VaR results against performance due to actual price movements. Based on the assumed 95% confidence interval, the performance due to actual price movements would be expected to exceed the VaR at least once every 20 trading days.

As our VaR calculation captures recent price movements, we also perform regular stress testing of the portfolio to understand our exposure to extreme price movements. We employ a historical-based method whereby the current portfolio is subjected to actual, observed price movements from the last four years in order to ascertain which historical price movements translated into the largest potential MTM loss. We then research the underlying positions, price movements and market events that created the most significant exposure and report the findings to the Risk Executive Committee or the CORC as appropriate.

Interest Rate Risk

We utilize an Earnings at Risk (EaR) model to measure interest rate market risk exposure. EaR statistically quantifies the extent to which our interest expense could vary over the next twelve months and gives a probabilistic estimate of different levels of interest expense. The resulting EaR is interpreted as the dollar amount by which actual interest expense for the next twelve months could exceed expected interest expense with a one-in-twenty chance of occurrence. The primary drivers of EaR are from the existing floating rate debt (including short-term debt) as well as long-term debt issuances in the next twelve months. As calculated on debt outstanding as of December 31, 2010 and 2009, the estimated EaR on our debt portfolio for the following twelve months was $5 million and $4 million, respectively.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of American Electric Power Company, Inc.:

We have audited the accompanying consolidated balance sheets of American Electric Power Company, Inc. and subsidiary companies (the "Company") as of December 31, 2010 and 2009, and the related consolidated statements of income, changes in equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2010. 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 the standards of the Public Company Accounting Oversight Board (United States). 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 American Electric Power Company, Inc. and subsidiary companies as of December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, the Company adopted FASB Accounting Standards Update No. 2009-16, *Transfers and Servicing (Topic 860): Accounting for Transfers of Financial Assets*, effective January 1, 2010.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2010, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 25, 2011 expressed an unqualified opinion on the Company's internal control over financial reporting.

Deloitte & Touche LLP

Columbus, Ohio
February 25, 2011

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of American Electric Power Company, Inc.:

We have audited the internal control over financial reporting of American Electric Power Company, Inc. and subsidiary companies (the "Company") as of December 31, 2010, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Report on Internal Control Over Financial Reporting*. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2010 of the Company and our report dated February 25, 2011 expressed an unqualified opinion on those financial statements and included an explanatory paragraph relating to the Company's adoption of a new accounting pronouncement.

Deloitte & Touche LLP

Columbus, Ohio
February 25, 2011

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of American Electric Power Company, Inc. and subsidiary companies (AEP) is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rule 13a-15 (f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. AEP's internal control system was designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of AEP's internal control over financial reporting as of December 31, 2010. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework. Based on management's assessment, AEP's internal control over financial reporting was effective as of December 31, 2010.

AEP's independent registered public accounting firm has issued an attestation report on AEP's internal control over financial reporting. The Report of Independent Registered Public Accounting Firm appears on the previous page.

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AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2010, 2009 and 2008
(in millions, except per-share and share amounts)

	2010	2009	2008
REVENUES			
Utility Operations	$ 13,687	$ 12,733	$ 13,326
Other Revenues	740	756	1,114
TOTAL REVENUES	14,427	13,489	14,440
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	4,029	3,478	4,474
Purchased Electricity for Resale	1,000	1,053	1,281
Other Operation	3,132	2,620	2,856
Maintenance	1,142	1,205	1,053
Gain on Settlement of TEM Litigation	-	-	(255)
Depreciation and Amortization	1,641	1,597	1,483
Taxes Other Than Income Taxes	820	765	761
TOTAL EXPENSES	11,764	10,718	11,653
OPERATING INCOME	2,663	2,771	2,787
Other Income (Expense):			
Interest and Investment Income	38	11	57
Carrying Costs Income	70	47	83
Allowance for Equity Funds Used During Construction	77	82	45
Interest Expense	(999)	(973)	(957)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS	1,849	1,938	2,015
Income Tax Expense	643	575	642
Equity Earnings of Unconsolidated Subsidiaries	12	7	3
INCOME BEFORE DISCONTINUED OPERATIONS AND EXTRAORDINARY LOSS	1,218	1,370	1,376
DISCONTINUED OPERATIONS, NET OF TAX	-	-	12
INCOME BEFORE EXTRAORDINARY LOSS	1,218	1,370	1,388
EXTRAORDINARY LOSS, NET OF TAX	-	(5)	-
NET INCOME	1,218	1,365	1,388
Less: Net Income Attributable to Noncontrolling Interests	4	5	5
NET INCOME ATTRIBUTABLE TO AEP SHAREHOLDERS	1,214	1,360	1,383
Less: Preferred Stock Dividend Requirements of Subsidiaries	3	3	3
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1,211	$ 1,357	$ 1,380
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	479,373,306	458,677,534	402,083,847
BASIC EARNINGS (LOSS) PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS			
Income Before Discontinued Operations and Extraordinary Loss	$ 2.53	$ 2.97	$ 3.40
Discontinued Operations, Net of Tax	-	-	0.03
Income Before Extraordinary Loss	2.53	2.97	3.43
Extraordinary Loss, Net of Tax	-	(0.01)	-
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 2.53	$ 2.96	$ 3.43
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	479,601,442	458,982,292	403,640,708
DILUTED EARNINGS (LOSS) PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS			
Income Before Discontinued Operations and Extraordinary Loss	$ 2.53	$ 2.97	$ 3.39
Discontinued Operations, Net of Tax	-	-	0.03
Income Before Extraordinary Loss	2.53	2.97	3.42
Extraordinary Loss, Net of Tax	-	(0.01)	-
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 2.53	$ 2.96	$ 3.42
CASH DIVIDENDS PAID PER SHARE	$ 1.71	$ 1.64	$ 1.64

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2010, 2009 and 2008
(in millions)

	AEP Common Shareholders						
	Common Stock				Accumulated Other		
	Shares	Amount	Paid-in Capital	Retained Earnings	Comprehensive Income (Loss)	Noncontrolling Interests	Total
TOTAL EQUITY – DECEMBER 31, 2007	422	$ 2,743	$ 4,352	$ 3,138	$ (154)	$ 18	$ 10,097
Adoption of Guidance for Split-Dollar Life Insurance Accounting, Net of Tax of $6				(10)			(10)
Adoption of Guidance for Fair Value Accounting, Net of Tax of $0				(1)			(1)
Issuance of Common Stock	4	28	131				159
Reissuance of Treasury Shares			40				40
Common Stock Dividends				(660)		(6)	(666)
Preferred Stock Dividend Requirements of Subsidiaries				(3)			(3)
Other Changes in Equity			4				4
SUBTOTAL – EQUITY							9,620
COMPREHENSIVE INCOME							
Other Comprehensive Income (Loss), Net of Taxes:							
Cash Flow Hedges, Net of Tax of $2					4		4
Securities Available for Sale, Net of Tax of $9					(16)		(16)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $7					12		12
Pension and OPEB Funded Status, Net of Tax of $161					(298)		(298)
NET INCOME				1,383		5	1,388
TOTAL COMPREHENSIVE INCOME							1,090
TOTAL EQUITY – DECEMBER 31, 2008	426	2,771	4,527	3,847	(452)	17	10,710
Issuance of Common Stock	72	468	1,311				1,779
Common Stock Dividends				(753)		(5)	(758)
Preferred Stock Dividend Requirements of Subsidiaries				(3)			(3)
Purchase of JMG			37			(18)	19
Other Changes in Equity			(51)			1	(50)
SUBTOTAL – EQUITY							11,697
COMPREHENSIVE INCOME							
Other Comprehensive Income, Net of Taxes:							
Cash Flow Hedges, Net of Tax of $4					7		7
Securities Available for Sale, Net of Tax of $6					11		11
Reapplication of Regulated Operations Accounting Guidance for Pensions, Net of Tax of $8					15		15
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $13					23		23
Pension and OPEB Funded Status, Net of Tax of $12					22		22
NET INCOME				1,360		5	1,365
TOTAL COMPREHENSIVE INCOME							1,443
TOTAL EQUITY – DECEMBER 31, 2009	498	3,239	5,824	4,451	(374)	-	13,140
Issuance of Common Stock	3	18	75				93
Common Stock Dividends				(820)		(4)	(824)
Preferred Stock Dividend Requirements of Subsidiaries				(3)			(3)
Other Changes in Equity			5				5
SUBTOTAL – EQUITY							12,411
COMPREHENSIVE INCOME							
Other Comprehensive Income (Loss), Net of Taxes:							
Cash Flow Hedges, Net of Tax of $14					26		26
Securities Available for Sale, Net of Tax of $4					(8)		(8)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $12					22		22
Pension and OPEB Funded Status, Net of Tax of $25					(47)		(47)
NET INCOME				1,214		4	1,218
TOTAL COMPREHENSIVE INCOME							1,211
TOTAL EQUITY – DECEMBER 31, 2010	501	$ 3,257	$ 5,904	$ 4,842	$ (381)	$ -	$ 13,622

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2010 and 2009
(in millions)

	2010	2009
CURRENT ASSETS		
Cash and Cash Equivalents	$ 294	$ 490
Other Temporary Investments		
(December 31, 2010 amount includes $287 related to Transition Funding and EIS)	416	363
Accounts Receivable:		
Customers	683	492
Accrued Unbilled Revenues	195	503
Pledged Accounts Receivable - AEP Credit	949	-
Miscellaneous	137	92
Allowance for Uncollectible Accounts	(41)	(37)
Total Accounts Receivable	1,923	1,050
Fuel	837	1,075
Materials and Supplies	611	586
Risk Management Assets	232	260
Accrued Tax Benefits	389	547
Regulatory Asset for Under-Recovered Fuel Costs	81	85
Margin Deposits	88	89
Prepayments and Other Current Assets	145	211
TOTAL CURRENT ASSETS	5,016	4,756
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	24,352	23,045
Transmission	8,576	8,315
Distribution	14,208	13,549
Other Property, Plant and Equipment (including nuclear fuel and coal mining)	3,846	3,744
Construction Work in Progress	2,758	3,031
Total Property, Plant and Equipment	53,740	51,684
Accumulated Depreciation and Amortization	18,066	17,340
TOTAL PROPERTY, PLANT AND EQUIPMENT - NET	35,674	34,344
OTHER NONCURRENT ASSETS		
Regulatory Assets	4,943	4,595
Securitized Transition Assets	1,742	1,896
Spent Nuclear Fuel and Decommissioning Trusts	1,515	1,392
Goodwill	76	76
Long-term Risk Management Assets	410	343
Deferred Charges and Other Noncurrent Assets	1,079	946
TOTAL OTHER NONCURRENT ASSETS	9,765	9,248
TOTAL ASSETS	$ 50,455	$ 48,348

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
December 31, 2010 and 2009
(dollars in millions)

	2010	2009
CURRENT LIABILITIES		
Accounts Payable	$ 1,061	$ 1,158
Short-term Debt:		
Securitized Debt for Receivables - AEP Credit	690	-
Other Short-term Debt	656	126
Total Short-term Debt	1,346	126
Long-term Debt Due Within One Year	1,309	1,741
Risk Management Liabilities	129	120
Customer Deposits	273	256
Accrued Taxes	702	632
Accrued Interest	281	287
Regulatory Liability for Over-Recovered Fuel Costs	17	76
Deferred Gain and Accrued Litigation Costs	448	-
Other Current Liabilities	952	931
TOTAL CURRENT LIABILITIES	6,518	5,327
NONCURRENT LIABILITIES		
Long-term Debt		
(December 31, 2010 amount includes $1,857 related to Transition Funding, DCC Fuel and Sabine)	15,502	15,757
Long-term Risk Management Liabilities	141	128
Deferred Income Taxes	7,359	6,420
Regulatory Liabilities and Deferred Investment Tax Credits	3,171	2,909
Asset Retirement Obligations	1,394	1,254
Employee Benefits and Pension Obligations	1,893	2,189
Deferred Credits and Other Noncurrent Liabilities	795	1,163
TOTAL NONCURRENT LIABILITIES	30,255	29,820
TOTAL LIABILITIES	36,773	35,147
Cumulative Preferred Stock Not Subject to Mandatory Redemption	60	61
Rate Matters (Note 4)		
Commitments and Contingencies (Note 6)		
EQUITY		
Common Stock – Par Value – $6.50 Per Share:		

	2010	2009
Shares Authorized	600,000,000	600,000,000
Shares Issued	501,114,881	498,333,265

	2010	2009
(20,307,725 shares and 20,278,858 shares were held in treasury at December 31, 2010 and 2009, respectively)	3,257	3,239
Paid-in Capital	5,904	5,824
Retained Earnings	4,842	4,451
Accumulated Other Comprehensive Income (Loss)	(381)	(374)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY	13,622	13,140
TOTAL EQUITY	13,622	13,140
TOTAL LIABILITIES AND EQUITY	$ 50,455	$ 48,348

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2010, 2009 and 2008
(in millions)

	2010	2009	2008
OPERATING ACTIVITIES			
Net Income	$ 1,218	$ 1,365	$ 1,388
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	1,641	1,597	1,483
Deferred Income Taxes	809	1,244	498
Provision for SIA Refund	-	-	149
Discontinued Operations, Net of Tax	-	-	(12)
Extraordinary Loss, Net of Tax	-	5	-
Carrying Costs Income	(70)	(47)	(83)
Allowance for Equity Funds Used During Construction	(77)	(82)	(45)
Mark-to-Market of Risk Management Contracts	30	(59)	(140)
Amortization of Nuclear Fuel	139	63	88
Pension Contributions to Qualified Plan Trust	(500)	-	-
Property Taxes	(21)	(17)	(13)
Fuel Over/Under-Recovery, Net	(253)	(474)	(272)
Gains on Sales of Assets, Net	(14)	(15)	(17)
Change in Other Noncurrent Assets	(75)	(137)	(244)
Change in Other Noncurrent Liabilities	202	244	8
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	(866)	41	71
Fuel, Materials and Supplies	221	(475)	(183)
Margin Deposits	1	(3)	(40)
Accounts Payable	(36)	8	(94)
Customer Deposits	14	2	(48)
Accrued Taxes, Net	179	(470)	4
Accrued Interest	(8)	17	30
Other Current Assets	72	(70)	(29)
Other Current Liabilities	56	(262)	82
Net Cash Flows from Operating Activities	2,662	2,475	2,581
INVESTING ACTIVITIES			
Construction Expenditures	(2,345)	(2,792)	(3,800)
Change in Other Temporary Investments, Net	(4)	16	45
Purchases of Investment Securities	(1,918)	(853)	(1,922)
Sales of Investment Securities	1,817	748	1,917
Acquisitions of Nuclear Fuel	(91)	(169)	(192)
Acquisitions of Assets	(155)	(104)	(160)
Proceeds from Sales of Assets	187	278	90
Other Investing Activities	(14)	(40)	(5)
Net Cash Flows Used for Investing Activities	(2,523)	(2,916)	(4,027)
FINANCING ACTIVITIES			
Issuance of Common Stock, Net	93	1,728	159
Issuance of Long-term Debt	1,270	2,306	2,774
Commercial Paper and Credit Facility Borrowings	565	127	2,055
Change in Short-term Debt, Net	770	119	(660)
Retirement of Long-term Debt	(1,993)	(816)	(1,824)
Commercial Paper and Credit Facility Repayments	(115)	(2,096)	(79)
Principal Payments for Capital Lease Obligations	(95)	(82)	(97)
Dividends Paid on Common Stock	(824)	(758)	(666)
Dividends Paid on Cumulative Preferred Stock	(3)	(3)	(3)
Other Financing Activities	(3)	(5)	20
Net Cash Flows from (Used for) Financing Activities	(335)	520	1,679
Net Increase (Decrease) in Cash and Cash Equivalents	(196)	79	233
Cash and Cash Equivalents at Beginning of Period	490	411	178
Cash and Cash Equivalents at End of Period	$ 294	$ 490	$ 411

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
INDEX OF NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

The principal business conducted by seven of our electric utility operating companies is the generation, transmission and distribution of electric power. TCC exited the generation business and along with KGPCo and WPCo, provides only transmission and distribution services. TNC engages in the transmission and distribution of electric power and is a part owner in the Oklaunion Plant operated by PSO. TNC leases their entire portion of the output of the plant through 2027 to a nonutility affiliate. AEGCo is a regulated electricity generation business whose function is to provide power to our regulated electric utility operating companies. These companies are subject to regulation by the FERC under the Federal Power Act and the Energy Policy Act of 2005. These companies maintain accounts in accordance with the FERC and other regulatory guidelines. These companies are subject to further regulation with regard to rates and other matters by state regulatory commissions.

We also engage in wholesale electricity, natural gas and other commodity marketing and risk management activities in the United States. In addition, our operations include nonregulated wind farms and barging operations and we provide various energy-related services.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

Our public utility subsidiaries' rates are regulated by the FERC and state regulatory commissions in our eleven state operating territories. The FERC also regulates our affiliated transactions, including AEPSC intercompany service billings which are generally at cost, under the 2005 Public Utility Holding Company Act and the Federal Power Act. The FERC also has jurisdiction over the issuances and acquisitions of securities of our public utility subsidiaries, the acquisition or sale of certain utility assets and mergers with another electric utility or holding company. For non-power goods and services, the FERC requires that a nonregulated affiliate can bill an affiliated public utility company no more than market while a public utility must bill the higher of cost or market to a nonregulated affiliate. The state regulatory commissions also regulate certain intercompany transactions under various orders and affiliate statutes. Both the FERC and state regulatory commissions are permitted to review and audit the relevant books and records of companies within a public utility holding company system.

The FERC regulates wholesale power markets and wholesale power transactions. Our wholesale power transactions are generally market-based. They are cost-based regulated when we negotiate and file a cost-based contract with the FERC or the FERC determines that we have "market power" in the region where the transaction occurs. We have entered into wholesale power supply contracts with various municipalities and cooperatives that are FERC-regulated, cost-based contracts. These contracts are generally formula rate mechanisms, which are trued up to actual costs annually. Our wholesale power transactions in the SPP region are cost-based due to PSO and SWEPCo having market power in the SPP region.

The state regulatory commissions regulate all of the distribution operations and rates of our retail public utilities on a cost basis. They also regulate the retail generation/power supply operations and rates except in Ohio and the ERCOT region of Texas. The ESP rates in Ohio continue the process of aligning generation/power supply rates over time with market rates. In the ERCOT region of Texas, the generation/supply business is under customer choice and market pricing and is conducted by REPs. Through its nonregulated subsidiaries, AEP enters into short and long-term wholesale transactions to buy or sell capacity, energy and ancillary services in the ERCOT market. In addition, these nonregulated subsidiaries control certain wind and coal-fired generation assets, the power from which is marketed and sold in ERCOT. Effective November 2009, AEP had no active REPs in ERCOT. SWEPCo operates in the SPP area which includes a portion of Texas. In 2009, the Texas legislature amended its restructuring legislation for the generation portion of SWEPCo's Texas retail jurisdiction to delay indefinitely restructuring requirements. As a result, SWEPCo reapplied accounting guidance for "Regulated Operations" to its Texas generation operations.

The FERC also regulates our wholesale transmission operations and rates. The FERC claims jurisdiction over retail transmission rates when retail rates are unbundled in connection with restructuring. CSPCo's and OPCo's retail transmission rates in Ohio, APCo's retail transmission rates in Virginia, I&M's retail transmission rates in Michigan and TCC's and TNC's retail transmission rates in Texas are unbundled. CSPCo's and OPCo's retail transmission rates in Ohio and APCo's retail transmission rates in Virginia are based on the FERC's Open Access Transmission Tariff (OATT) rates that are cost-based. Although I&M's retail transmission rates in Michigan and TCC's and TNC's retail transmission rates in Texas are unbundled, retail transmission rates are regulated, on a cost basis, by the state regulatory commissions. Bundled retail transmission rates are regulated, on a cost basis, by the state commissions.

In addition, the FERC regulates the SIA, the Interconnection Agreement, the CSW Operating Agreement, the System Transmission Integration Agreement, the Transmission Agreement, the Transmission Coordination Agreement and the AEP System Interim Allowance Agreement, all of which allocate shared system costs and revenues to the utility subsidiaries that are parties to each agreement.

Principles of Consolidation

Our consolidated financial statements include our wholly-owned and majority-owned subsidiaries and variable interest entities (VIEs) of which we are the primary beneficiary. Intercompany items are eliminated in consolidation. We use the equity method of accounting for equity investments where we exercise significant influence but do not hold a controlling financial interest. Such investments are recorded as Deferred Charges and Other Noncurrent Assets on our Consolidated Balance Sheets; equity earnings are included in Equity Earnings of Unconsolidated Subsidiaries on our Consolidated Statements of Income. We have ownership interests in generating units that are jointly-owned with nonaffiliated companies. Our proportionate share of the operating costs associated with such facilities is included on our Consolidated Statements of Income and our proportionate share of the assets and liabilities are reflected on our Consolidated Balance Sheets.

Variable Interest Entities

The accounting guidance for "Variable Interest Entities" is a consolidation model that considers if a company has a controlling financial interest in a VIE. A controlling financial interest will have both (a) the power to direct the activities of a VIE that most significantly impact the VIE's economic performance and (b) the obligation to absorb losses of the VIE that could potentially be significant to the VIE or the right to receive benefits from the VIE that could potentially be significant to the VIE. Entities are required to consolidate a VIE when it is determined that they have a controlling financial interest in a VIE and therefore, are the primary beneficiary of that VIE, as defined by the accounting guidance for "Variable Interest Entities." In determining whether we are the primary beneficiary of a VIE, we consider factors such as equity at risk, the amount of the VIE's variability we absorb, guarantees of indebtedness, voting rights including kick-out rights, power to direct the VIE and other factors. We believe that significant assumptions and judgments were applied consistently. Also, see the "ASU 2009-17 'Consolidations' " section of Note 2 for a discussion of the impact of new accounting guidance effective January 1, 2010.

We are the primary beneficiary of Sabine, DCC Fuel LLC, DCC Fuel II LLC, DCC Fuel III LLC, AEP Credit, Transition Funding and a protected cell of EIS. As of January 1, 2010, we are no longer the primary beneficiary of DHLC as defined by the new accounting guidance for "Variable Interest Entities." In addition, we have not provided material financial or other support to Sabine, DCC Fuel LLC, DCC Fuel II LLC, DCC Fuel III LLC, Transition Funding, our protected cell of EIS and AEP Credit that was not previously contractually required. We hold a significant variable interest in Potomac-Appalachian Transmission Highline, LLC West Virginia Series (West Virginia Series) and DHLC.

Sabine is a mining operator providing mining services to SWEPCo. SWEPCo has no equity investment in Sabine but is Sabine's only customer. SWEPCo guarantees the debt obligations and lease obligations of Sabine. Under the terms of the note agreements, substantially all assets are pledged and all rights under the lignite mining agreement are assigned to SWEPCo. The creditors of Sabine have no recourse to any AEP entity other than SWEPCo. Under the provisions of the mining agreement, SWEPCo is required to pay, as a part of the cost of lignite delivered, an amount equal to mining costs plus a management fee. In addition, SWEPCo determines how much coal will be mined for each year. Based on these facts, management concluded that SWEPCo is the primary beneficiary and is required to consolidate Sabine. SWEPCo's total billings from Sabine for the years ended December 31, 2010, 2009 and 2008 were $133 million, $99 million and $110 million, respectively. See the tables below for the classification of Sabine's assets and liabilities on our Consolidated Balance Sheets.

Our subsidiaries participate in one protected cell of EIS for approximately ten lines of insurance. EIS has multiple protected cells. Neither AEP nor its subsidiaries have an equity investment in EIS. The AEP System is essentially this EIS cell's only participant, but allows certain third parties access to this insurance. Our subsidiaries and any allowed third parties share in the insurance coverage, premiums and risk of loss from claims. Based on our control and the structure of the protected cell and EIS, management concluded that we are the primary beneficiary of the protected cell and are required to consolidate its assets and liabilities. Our insurance premium payments to the protected cell for the years ended December 31, 2010, 2009 and 2008 were $35 million, $30 million and $28 million, respectively. See the tables below for the classification of the protected cell's assets and liabilities on our Consolidated Balance Sheets. The amount reported as equity is the protected cell's policy holders' surplus.

In September 2009, I&M entered into a nuclear fuel sale and leaseback transaction with DCC Fuel LLC. In April 2010, I&M entered into a nuclear fuel sale and leaseback transaction with DCC Fuel II LLC. In December 2010, I&M entered into a nuclear fuel sale and leaseback transaction with DCC Fuel III LLC. DCC Fuel LLC, DCC Fuel II LLC and DCC Fuel III LLC (collectively DCC Fuel) were formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M. DCC Fuel purchased the nuclear fuel from I&M with funds received from the issuance of notes to financial institutions. Each entity is a single-lessee leasing arrangement with only one asset and is capitalized with all debt. DCC Fuel LLC, DCC Fuel II LLC and DCC Fuel III LLC are separate legal entities from I&M, the assets of which are not available to satisfy the debts of I&M. Payments on the DCC Fuel LLC and DCC Fuel II LLC leases are made semi-annually and began in April 2010 and October 2010, respectively. Payments on the DCC Fuel III LLC lease are made monthly and will begin in January 2011. Payments on the leases for the year ended December 31, 2010 were $59 million. No payments were made to DCC Fuel in 2009. The leases were recorded as capital leases on I&M's balance sheet as title to the nuclear fuel transfers to I&M at the end of the 48, 54 and 54 month lease term, respectively. Based on our control of DCC Fuel, management concluded that I&M is the primary beneficiary and is required to consolidate DCC Fuel. The capital leases are eliminated upon consolidation. See the tables below for the classification of DCC Fuel's assets and liabilities on our Consolidated Balance Sheets.

AEP Credit is a wholly-owned subsidiary of AEP. AEP Credit purchases, without recourse, accounts receivable from certain utility subsidiaries of AEP to reduce working capital requirements. AEP Parent provides a minimum of 5% equity and up to 20% of AEP Credit's short-term borrowing needs in excess of third party financings. Any third party financing of AEP Credit only has recourse to the receivables securitized for such financing. Based on our control of AEP Credit, management has concluded that we are the primary beneficiary and are required to consolidate its assets and liabilities. See the tables below for the classification of AEP Credit's assets and liabilities on our Consolidated Balance Sheets. See the "ASU 2009-17 'Consolidation' " section of Note 2 for a discussion of the impact of new accounting guidance effective January 1, 2010. Also, see "Securitized Accounts Receivables – AEP Credit" section of Note 14.

DHLC is a mining operator who sells 50% of the lignite produced to SWEPCo and 50% to CLECO. SWEPCo and CLECO share the executive board seats and its voting rights equally. Each entity guarantees a 50% share of DHLC's debt. SWEPCo and CLECO equally approve DHLC's annual budget. The creditors of DHLC have no recourse to any AEP entity other than SWEPCo. As SWEPCo is the sole equity owner of DHLC, it receives 100% of the management fee. Based on the shared control of DHLC's operations, management concluded as of January 1, 2010 that SWEPCo is no longer the primary beneficiary and is no longer required to consolidate DHLC. SWEPCo's total billings from DHLC for the years ended December 31, 2010, 2009 and 2008 were $56 million, $43 million and $44 million, respectively. See the tables below for the classification of DHLC's assets and liabilities on our Consolidated Balance Sheets at December 31, 2009 as well as our investment and maximum exposure as of December 31, 2010. As of January 1, 2010, DHLC is reported as an equity investment in Deferred Charges and Other Noncurrent Assets on our Consolidated Balance Sheets. Also, see the "ASU 2009-17 'Consolidations' " section of Note 2 for a discussion of the impact of new accounting guidance effective January 1, 2010.

Transition Funding was formed for the sole purpose of issuing and servicing securitization bonds related to Texas restructuring law. Management has concluded that TCC is the primary beneficiary of Transition Funding because TCC has the power to direct the most significant activities of the VIE and TCC's equity interest could potentially be significant. Therefore, TCC is required to consolidate Transition Funding. The securitized bonds totaled $1.8 billion at December 31, 2010 and are included in current and long-term debt on the Consolidated Balance Sheets. Transition Funding has securitized transition assets of $1.7 billion at December 31, 2010, which are presented separately on the face of the Consolidated Balance Sheets. The securitized transition assets represent the right to impose and collect Texas true-up costs from customers receiving electric transmission or distribution service from TCC under recovery mechanisms approved by the PUCT. The securitization bonds are payable only from and secured by the securitized transition assets. The bondholders have no recourse to TCC or any other AEP entity. TCC acts as the servicer for Transition Funding's securitized transition assets and remits all related amounts collected from customers to Transition Funding for interest and principal payments on the securitization bonds and related costs.

The balances below represent the assets and liabilities of the VIEs that are consolidated. These balances include intercompany transactions that are eliminated upon consolidation.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
VARIABLE INTEREST ENTITIES
December 31, 2010
(in millions)

	SWEPCo Sabine	I&M DCC Fuel	Protected Cell of EIS	AEP Credit	Transition Funding
ASSETS					
Current Assets	$ 50	$ 92	$ 131	$ 924	$ 214
Net Property, Plant and Equipment	139	173	-	-	-
Other Noncurrent Assets	34	112	1	10	1,746
Total Assets	$ 223	$ 377	$ 132	$ 934	$ 1,960
LIABILITIES AND EQUITY					
Current Liabilities	$ 33	$ 79	$ 33	$ 886	$ 221
Noncurrent Liabilities	190	298	85	1	1,725
Equity	-	-	14	47	14
Total Liabilities and Equity	$ 223	$ 377	$ 132	$ 934	$ 1,960

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
VARIABLE INTEREST ENTITIES
December 31, 2009
(in millions)

	SWEPCo Sabine	SWEPCo DHLC	I&M DCC Fuel	Protected Cell of EIS
ASSETS				
Current Assets	$ 51	$ 8	$ 47	$ 130
Net Property, Plant and Equipment	149	44	89	-
Other Noncurrent Assets	35	11	57	2
Total Assets	$ 235	$ 63	$ 193	$ 132
LIABILITIES AND EQUITY				
Current Liabilities	$ 36	$ 17	$ 39	$ 36
Noncurrent Liabilities	199	38	154	74
Equity	-	8	-	22
Total Liabilities and Equity	$ 235	$ 63	$ 193	$ 132

Our investment in DHLC was:

	December 31, 2010	
	As Reported on the Consolidated Balance Sheets	Maximum Exposure
	(in millions)	
Capital Contribution from SWEPCo	$ 6	$ 6
Retained Earnings	2	2
SWEPCo's Guarantee of Debt	-	48
Total Investment in DHLC	$ 8	$ 56

In September 2007, we and Allegheny Energy Inc. (AYE) formed a joint venture by creating Potomac-Appalachian Transmission Highline, LLC (PATH). PATH is a series limited liability company and was created to construct a high-voltage transmission line project in the PJM region. PATH consists of the "Ohio Series," the "West Virginia Series (PATH-WV)," both owned equally by AYE and AEP, and the "Allegheny Series" which is 100% owned by AYE. Provisions exist within the PATH-WV agreement that make it a VIE. The "Ohio Series" does not include the same provisions that make PATH-WV a VIE. Neither the "Ohio Series" nor "Allegheny Series" are considered VIEs. We are not required to consolidate PATH-WV as we are not the primary beneficiary, although we hold a significant variable interest in PATH-WV. Our equity investment in PATH-WV is included in Deferred Charges and Other Noncurrent Assets on our Consolidated Balance Sheets. We and AYE share the returns and losses equally in PATH-WV. Our subsidiaries and AYE's subsidiaries provide services to the PATH companies through service agreements. At the current time, PATH-WV has no debt outstanding. However, when debt is issued, the debt to equity ratio in each series should be consistent with other regulated utilities. The entities recover costs through regulated rates.

Given the structure of the entity, we may be required to provide future financial support to PATH-WV in the form of a capital call. This would be considered an increase to our investment in the entity. Our maximum exposure to loss is to the extent of our investment. The likelihood of such a loss is remote since the FERC approved PATH-WV's request for regulatory recovery of cost and a return on the equity invested.

Our investment in PATH-WV was:

	December 31,			
	2010		2009	
	As Reported on the Consolidated Balance Sheets	**Maximum Exposure**	**As Reported on the Consolidated Balance Sheets**	**Maximum Exposure**
	(in millions)			
Capital Contribution from AEP	$ 18	$ 18	$ 13	$ 13
Retained Earnings	6	6	3	3
Total Investment in PATH-WV	$ 24	$ 24	$ 16	$ 16

Accounting for the Effects of Cost-Based Regulation

As the owner of rate-regulated electric public utility companies, our consolidated financial statements reflect the actions of regulators that result in the recognition of certain revenues and expenses in different time periods than enterprises that are not rate-regulated. In accordance with accounting guidance for "Regulated Operations," we record regulatory assets (deferred expenses) and regulatory liabilities (future revenue reductions or refunds) to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues and income with its passage to customers through the reduction of regulated revenues. Due to the passage of legislation requiring restructuring and a transition to customer choice and market-based rates, we discontinued the application of "Regulated Operations" accounting treatment for the generation portion of our business in Ohio for CSPCo and OPCo and in Texas for TNC. In 2009, the Texas legislature amended its restructuring legislation for the generation portion of SWEPCo's Texas retail jurisdiction to delay indefinitely restructuring requirements. As a result, SWEPCo reapplied accounting guidance for "Regulated Operations" to its Texas generation operations.

Accounting guidance for "Discontinuation of Rate-Regulated Operations" requires the recognition of an impairment of stranded net regulatory assets and stranded plant costs if they are not recoverable in regulated rates. In addition, an enterprise is required to eliminate from its balance sheet the effects of any actions of regulators that had been recognized as regulatory assets and regulatory liabilities. Such impairments and adjustments are classified as an extraordinary item. Consistent with accounting guidance for "Discontinuation of Rate-Regulated Operations," SWEPCo recorded an extraordinary reduction in earnings and shareholder's equity from the reapplication of "Regulated Operations" accounting guidance in 2009.

Use of Estimates

The preparation of these financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. These estimates include, but are not limited to, inventory valuation, allowance for doubtful accounts, goodwill, intangible and long-lived asset impairment, unbilled electricity revenue, valuation of long-term energy contracts, the effects of regulation, long-lived asset recovery, storm costs, the effects of contingencies and certain assumptions made in accounting for pension and postretirement benefits. The estimates and assumptions used are based upon management's evaluation of the relevant facts and circumstances as of the date of the financial statements. Actual results could ultimately differ from those estimates.

Cash and Cash Equivalents

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

Other Temporary Investments

Other Temporary Investments include marketable securities that we intend to hold for less than one year, investments by our protected cell of EIS and funds held by trustees primarily for the payment of debt.

We classify our investments in marketable securities as available-for-sale or held-to-maturity in accordance with the provisions of "Investments – Debt and Equity Securities" accounting guidance. We do not have any investments classified as trading.

Available-for-sale securities reflected in Other Temporary Investments are carried at fair value with the unrealized gain or loss, net of tax, reported in AOCI. Held-to-maturity securities reflected in Other Temporary Investments are carried at amortized cost. The cost of securities sold is based on the specific identification or weighted average cost method.

In evaluating potential impairment of securities with unrealized losses, we considered, among other criteria, the current fair value compared to cost, the length of time the security's fair value has been below cost, our intent and ability to retain the investment for a period of time sufficient to allow for any anticipated recovery in value and current economic conditions. See "Fair Value Measurements of Other Temporary Investments" in Note 11.

Inventory

Fossil fuel inventories are generally carried at average cost. Materials and supplies inventories are carried at average cost.

Accounts Receivable

Customer accounts receivable primarily include receivables from wholesale and retail energy customers, receivables from energy contract counterparties related to our risk management activities and customer receivables primarily related to other revenue-generating activities.

We recognize revenue from electric power sales when we deliver power to our customers. To the extent that deliveries have occurred but a bill has not been issued, we accrue and recognize, as Accrued Unbilled Revenues on our Consolidated Balance Sheets, an estimate of the revenues for energy delivered since the last billing.

AEP Credit factors accounts receivable on a daily basis, excluding receivables from risk management activities, for CSPCo, I&M, KGPCo, KPCo, OPCo, PSO, SWEPCo and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in its West Virginia regulatory jurisdiction, only a portion of APCo's accounts receivable are sold to AEP Credit. AEP Credit has a receivables securitization agreement with bank conduits. Under the securitization agreement, AEP Credit receives financing from the bank conduits for the interest in the billed and unbilled receivables AEP Credit acquires from affiliated utility subsidiaries. Prior to January 1, 2010, this transaction constituted a sale of receivables in accordance with the accounting guidance for "Transfers and Servicing," allowing the receivables to be removed from our Consolidated Balance Sheets (see "Securitized

Accounts Receivable – AEP Credit" section of Note 14). See "ASU 2009-16 'Transfers and Servicing' " section of Note 2 for a discussion of the impact of accounting guidance effective January 1, 2010 whereby such future transactions do not constitute a sale of receivables and are accounted for as financings.

Allowance for Uncollectible Accounts

Generally, AEP Credit records bad debt expense based upon a 12-month rolling average of bad debt write-offs in proportion to gross accounts receivable purchased from participating AEP subsidiaries. For receivables related to APCo's West Virginia operations, the bad debt reserve is calculated based on a rolling two-year average write-off in proportion to gross accounts receivable. For customer accounts receivables related to our risk management activities, accounts receivables are reviewed for bad debt reserves at a specific counterparty level basis. For the wires business of TCC and TNC, bad debt reserves are calculated using the specific identification of receivable balances greater than 120 days delinquent. For miscellaneous accounts receivable, bad debt expense is recorded for all amounts outstanding 180 days or greater at 100%, unless specifically identified. Miscellaneous accounts receivable items open less than 180 days may be reserved using specific identification for bad debt reserves.

Emission Allowances

We record emission allowances at cost, including the annual SO_2 and NO_x emission allowance entitlements received at no cost from the Federal EPA. We follow the inventory model for these allowances. We record allowances expected to be consumed within one year in Materials and Supplies and allowances with expected consumption beyond one year in Deferred Charges and Other Noncurrent Assets on our Consolidated Balance Sheets. We record the consumption of allowances in the production of energy in Fuel and Other Consumables Used for Electric Generation on our Consolidated Statements of Income at an average cost. We record allowances held for speculation in Prepayments and Other Current Assets on our Consolidated Balance Sheets. We report the purchases and sales of allowances in the Operating Activities section of the Statements of Cash Flows. We record the net margin on sales of emission allowances in Utility Operations Revenue on our Consolidated Statements of Income because of its integral nature to the production process of energy and our revenue optimization strategy for our utility operations. The net margin on sales of emission allowances affects the determination of deferred fuel or deferred emission allowance costs and the amortization of regulatory assets for certain jurisdictions.

Property, Plant and Equipment and Equity Investments

Regulated

Electric utility property, plant and equipment for our rate-regulated operations are stated at original purchase cost. Additions, major replacements and betterments are added to the plant accounts. Normal and routine retirements from the plant accounts, net of salvage, are charged to accumulated depreciation under the group composite method of depreciation. The group composite method of depreciation assumes that on average, asset components are retired at the end of their useful lives and thus there is no gain or loss. The equipment in each primary electric plant account is identified as a separate group. Under the group composite method of depreciation, continuous interim routine replacements of items such as boiler tubes, pumps, motors, etc. result in the original cost, less salvage, being charged to accumulated depreciation. The depreciation rates that are established take into account the past history of interim capital replacements and the amount of salvage received. These rates and the related lives are subject to periodic review. Removal costs are charged to regulatory liabilities. The costs of labor, materials and overhead incurred to operate and maintain our plants are included in operating expenses.

Long-lived assets are required to be tested for impairment when it is determined that the carrying value of the assets may no longer be recoverable or when the assets meet the held for sale criteria under the accounting guidance for "Impairment or Disposal of Long-Lived Assets." Equity investments are required to be tested for impairment when it is determined there may be an other-than-temporary loss in value.

The fair value of an asset or investment is the amount at which that asset or investment could be bought or sold in a current transaction between willing parties, as opposed to a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets or investments in active markets, fair value is estimated using various internal and external valuation methods including cash flow analysis and appraisals.

Nonregulated

Our nonregulated operations generally follow the policies of our cost-based rate-regulated operations listed above but with the following exceptions. Property, plant and equipment of nonregulated operations and equity investments (included in Deferred Charges and Other Noncurrent Assets) are stated at fair value at acquisition (or as adjusted for any applicable impairments) plus the original cost of property acquired or constructed since the acquisition, less disposals. Normal and routine retirements from the plant accounts, net of salvage, are charged to accumulated depreciation for most nonregulated operations under the group composite method of depreciation. For nonregulated plant assets, a gain or loss would be recorded if the retirement is not considered an interim routine replacement. Removal costs are charged to expense.

Allowance for Funds Used During Construction (AFUDC) and Interest Capitalization

AFUDC represents the estimated cost of borrowed and equity funds used to finance construction projects that is capitalized and recovered through depreciation over the service life of regulated electric utility plant. For nonregulated operations, including generating assets in Ohio and certain generating assets in Texas, interest is capitalized during construction in accordance with the accounting guidance for "Capitalization of Interest". We record the equity component of AFUDC in Allowance for Equity Funds Used During Construction and the debt component of AFUDC as a reduction to Interest Expense.

Valuation of Nonderivative Financial Instruments

The book values 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 best estimate of its fair value.

Fair Value Measurements of Assets and Liabilities

The accounting guidance for "Fair Value Measurements and Disclosures" establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. When quoted market prices are not available, pricing may be completed using comparable securities, dealer values, operating data and general market conditions to determine fair value. Valuation models utilize various inputs such as commodity, interest rate and, to a lesser degree, volatility or credit that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability.

For our commercial activities, exchange traded derivatives, namely futures contracts, are generally fair valued based on unadjusted quoted prices in active markets and are classified as Level 1. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, as well as exchange traded contracts where there is insufficient market liquidity to warrant inclusion in Level 1. We verify our price curves using these broker quotes and classify these fair values within Level 2 when substantially all of the fair value can be corroborated. We typically obtain multiple broker quotes, which are non-binding in nature, but are based on recent trades in the marketplace. When multiple broker quotes are obtained, we average the quoted bid and ask prices. In certain circumstances, we may discard a broker quote if it is a clear outlier. We use a historical correlation analysis between the broker quoted location and the illiquid locations and if the points are highly correlated we include these locations within Level 2 as well. Certain OTC and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. Long-dated and illiquid complex or structured transactions and FTRs can introduce the need for internally developed modeling inputs based upon extrapolations and assumptions of observable market data to estimate fair value. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized as Level 3.

We utilize our trustee's external pricing service in our estimate of the fair value of the underlying investments held in the benefit plan and nuclear trusts. Our investment managers review and validate the prices utilized by the trustee to determine fair value. We perform our own valuation testing to verify the fair values of the securities. We receive audit reports of our trustee's operating controls and valuation processes. The trustee uses multiple pricing vendors for the assets held in the plans.

Assets in the benefits and nuclear trusts, Cash and Cash Equivalents and Other Temporary Investments are classified using the following methods. Equities are classified as Level 1 holdings if they are actively traded on exchanges. Items classified as Level 1 are investments in money market funds, fixed income and equity mutual funds and domestic equity securities. They are valued based on observable inputs primarily unadjusted quoted prices in active markets for identical assets. Fixed income securities do not trade on an exchange and do not have an official closing price. Pricing vendors calculate bond valuations using financial models and matrices. Fixed income securities are typically classified as Level 2 holdings because their valuation inputs are based on observable market data. Observable inputs used for valuing fixed income securities are benchmark yields, reported trades, broker/dealer quotes, issuer spreads, two-sided markets, benchmark securities, bids, offers, reference data and economic events. Other securities with model-derived valuation inputs that are observable are also classified as Level 2 investments. Investments with unobservable valuation inputs are classified as Level 3 investments. Benefit plan assets included in Level 3 are real estate and private equity investments that are valued using methods requiring judgment including appraisals.

Items classified as Level 2 are primarily investments in individual fixed income securities. These fixed income securities are valued using models with input data as follows:

	Type of Fixed Income Security		
Type of Input	**United States Government**	**Corporate Debt**	**State and Local Government**
Benchmark Yields	X	X	X
Broker Quotes	X	X	X
Discount Margins	X	X	
Treasury Market Update	X		
Base Spread	X	X	X
Corporate Actions		X	
Ratings Agency Updates		X	X
Prepayment Schedule and History			X
Yield Adjustments	X		

Deferred Fuel Costs

The cost of fuel and related emission allowances and emission control chemicals/consumables is charged to Fuel and Other Consumables Used for Electric Generation expense when the fuel is burned or the allowance or consumable is utilized. The cost of fuel also includes the cost of nuclear fuel burned which is computed primarily on the units-of-production method. In regulated jurisdictions with an active FAC, fuel cost over-recoveries (the excess of fuel revenues billed to customers over applicable fuel costs incurred) are generally deferred as current regulatory liabilities and under-recoveries (the excess of applicable fuel costs incurred over fuel revenues billed to customers) are generally deferred as current regulatory assets. These deferrals are amortized when refunded or when billed to customers in later months with the state regulatory commissions' review and approval. The amount of an over-recovery or under-recovery can also be affected by actions of the state regulatory commissions. On a routine basis, state regulatory commissions review and/or audit our fuel procurement policies and practices, the fuel cost calculations and FAC deferrals. When a fuel cost disallowance becomes probable, we adjust our FAC deferrals and record provisions for estimated refunds to recognize these probable outcomes. Fuel cost over-recovery and under-recovery balances are classified as noncurrent when there is a phase-in plan or the FAC has been suspended.

Changes in fuel costs, including purchased power in Kentucky for KPCo, in Indiana and Michigan for I&M, in Texas, Louisiana and Arkansas for SWEPCo, in Oklahoma for PSO and in Virginia and West Virginia (prior to 2009) for APCo are reflected in rates in a timely manner through the FAC. Beginning in 2009, changes in fuel costs, including purchased power in Ohio for CSPCo and OPCo and in West Virginia for APCo are reflected in rates through FAC phase-in plans. All of the profits from off-system sales are given to customers through the FAC in West Virginia for APCo. A portion of profits from off-system sales are shared with customers through the FAC and other rate mechanisms in Oklahoma for PSO, Texas, Louisiana and Arkansas for SWEPCo, Kentucky for KPCo, Virginia for APCo and in Indiana and Michigan (all areas of Michigan beginning in December 2010) for I&M. Where the FAC or off-system sales sharing mechanism is capped, frozen or non-existent (prior to 2009 for CSPCo and OPCo in Ohio and currently in Texas for AEP Energy Partners, Inc.), changes in fuel costs or sharing of off-system sales impacted earnings.

Revenue Recognition

Regulatory Accounting

Our consolidated financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated. Regulatory assets (deferred expenses) and regulatory liabilities (deferred revenue reductions or refunds) are recorded to reflect the economic effects of regulation in the same accounting period by matching expenses with their recovery through regulated revenues and by matching income with its passage to customers in cost-based regulated rates.

When regulatory assets are probable of recovery through regulated rates, we record them as assets on our Consolidated Balance Sheets. We test for probability of recovery at each balance sheet date or whenever new events occur. Examples of new events include the issuance of a regulatory commission order or passage of new legislation. If it is determined that recovery of a regulatory asset is no longer probable, we write off that regulatory asset as a charge against income.

Traditional Electricity Supply and Delivery Activities

Revenues are recognized from retail and wholesale electricity sales and electricity transmission and distribution delivery services. We recognize the revenues on our Consolidated Statements of Income upon delivery of the energy to the customer and include unbilled as well as billed amounts. In accordance with the applicable state commission regulatory treatment, PSO and SWEPCo do not record the fuel portion of unbilled revenue.

Most of the power produced at the generation plants of the AEP East companies is sold to PJM, the RTO operating in the east service territory. We purchase power from PJM to supply our customers. Generally, these power sales and purchases are reported on a net basis as revenues on our Consolidated Statements of Income. However, purchases of power in excess of sales to PJM, on an hourly net basis, used to serve retail load are recorded gross as Purchased Electricity for Resale on our Consolidated Statements of Income. Other RTOs in which we operate do not function in the same manner as PJM. They function as balancing organizations and not as exchanges.

Physical energy purchases arising from non-derivative contracts are accounted for on a gross basis in Purchased Electricity for Resale on our Consolidated Statements of Income. Energy purchases arising from non-trading derivative contracts are recorded based on the transaction's economic substance. Purchases under non-trading derivatives used to serve accrual based obligations are recorded in Purchased Electricity for Resale on our Consolidated Statements of Income. All other non-trading derivative purchases are recorded net in revenues.

In general, we record expenses when purchased electricity is received and when expenses are incurred, with the exception of certain power purchase contracts that are derivatives and accounted for using MTM accounting where generation/supply rates are not cost-based regulated. In jurisdictions where the generation/supply business is subject to cost-based regulation, the unrealized MTM amounts are deferred as regulatory assets (for losses) and regulatory liabilities (for gains).

Energy Marketing and Risk Management Activities

We engage in wholesale electricity, natural gas, coal and emission allowances marketing and risk management activities focused on wholesale markets where we own assets and on adjacent markets. Our activities include the purchase and sale of energy under forward contracts at fixed and variable prices and the buying and selling of financial energy contracts, which include exchange traded futures and options, as well as over-the-counter options and swaps. We engage in certain energy marketing and risk management transactions with RTOs.

We recognize revenues and expenses from wholesale marketing and risk management transactions that are not derivatives upon delivery of the commodity. We use MTM accounting for wholesale marketing and risk management transactions that are derivatives unless the derivative is designated in a qualifying cash flow hedge relationship or a normal purchase or sale. We include the unrealized and realized gains and losses on wholesale marketing and risk management transactions that are accounted for using MTM in Revenues on our Consolidated Statements of Income on a net basis. In jurisdictions subject to cost-based regulation, we defer the unrealized MTM amounts and some realized gains and losses as regulatory assets (for losses) and regulatory liabilities (for gains). We include unrealized MTM gains and losses resulting from derivative contracts on our Consolidated Balance Sheets as Risk Management Assets or Liabilities as appropriate.

Certain qualifying wholesale marketing and risk management derivative transactions are designated as hedges of variability in future cash flows as a result of forecasted transactions (cash flow hedge). We initially record the effective portion of the cash flow hedge's gain or loss as a component of AOCI. When the forecasted transaction is realized and affects net income, we subsequently reclassify the gain or loss on the hedge from AOCI into revenues or expenses within the same financial statement line item as the forecasted transaction on our Consolidated Statements of Income. Excluding those jurisdictions subject to cost-based regulation, we recognize the ineffective portion of the gain or loss in revenues or expense immediately on our Consolidated Statements of Income, depending on the specific nature of the associated hedged risk. In regulated jurisdictions, we defer the ineffective portion as regulatory assets (for losses) and regulatory liabilities (for gains) (see "Accounting for Cash Flow Hedging Strategies" section of Note 10).

Barging Activities

AEP River Operations' revenue is recognized based on percentage of voyage completion. The proportion of freight transportation revenue to be recognized is determined by applying a percentage to the contractual charges for such services. The percentage is determined by dividing the number of miles from the loading point to the position of the barge as of the end of the accounting period by the total miles to the destination specified in the customer's freight contract. The position of the barge at accounting period end is determined by our computerized barge tracking system.

Levelization of Nuclear Refueling Outage Costs

In order to match costs with nuclear refueling cycles, I&M defers incremental operation and maintenance costs associated with periodic refueling outages at its Cook Plant and amortizes the costs over the period beginning with the month following the start of each unit's refueling outage and lasting until the end of the month in which the same unit's next scheduled refueling outage begins. I&M adjusts the amortization amount as necessary to ensure full amortization of all deferred costs by the end of the refueling cycle.

Maintenance

We expense maintenance costs as incurred. If it becomes probable that we will recover specifically-incurred costs through future rates, we establish a regulatory asset to match the expensing of those maintenance costs with their recovery in cost-based regulated revenues. We defer distribution tree trimming costs for PSO above the level included in base rates and amortize those deferrals commensurate with recovery through a rate rider in Oklahoma.

Income Taxes and Investment Tax Credits

We use the liability method of accounting for income taxes. Under the liability method, we provide deferred income taxes for all temporary differences between the book and tax basis of assets and liabilities which will result in a future tax consequence.

When the flow-through method of accounting for temporary differences is reflected in regulated revenues (that is, when deferred taxes are not included in the cost of service for determining regulated rates for electricity), we record deferred income taxes and establish related regulatory assets and liabilities to match the regulated revenues and tax expense.

We account for investment tax credits under the flow-through method except where regulatory commissions reflect investment tax credits in the rate-making process on a deferral basis. We amortize deferred investment tax credits over the life of the plant investment.

We account for uncertain tax positions in accordance with the accounting guidance for "Income Taxes." We classify interest expense or income related to uncertain tax positions as interest expense or income as appropriate and classify penalties as Other Operation.

Excise Taxes

We act as an agent for some state and local governments and collect from customers certain excise taxes levied by those state or local governments on our customers. We do not recognize these taxes as revenue or expense.

Government Grants

In 2010, APCo received final approval for a federal stimulus grant for a commercial scale Carbon Capture and Sequestration facility under consideration at the Mountaineer Plant. Also in 2010, CSPCo received final approval for a federal stimulus grant for the gridSMART® demonstration program. For each project, APCo and CSPCo are reimbursed by the Department of Energy for allowable costs incurred during the billing period. These reimbursements result in the reduction of Other Operation and Maintenance expenses on our Consolidated Statements of Income or a reduction in Construction Work in Progress on our Consolidated Balance Sheets.

Debt and Preferred Stock

We defer gains and losses from the reacquisition of debt used to finance regulated electric utility plants and amortize the deferral over the remaining term of the reacquired debt in accordance with their rate-making treatment unless the debt is refinanced. If we refinance the reacquired debt associated with the regulated business, the reacquisition costs attributable to the portions of the business subject to cost-based regulatory accounting are generally deferred and amortized over the term of the replacement debt consistent with its recovery in rates. Some jurisdictions require that these costs be expensed upon reacquisition. We report gains and losses on the reacquisition of debt for operations not subject to cost-based rate regulation in Interest Expense on our Consolidated Statements of Income.

We defer debt discount or premium and debt issuance expenses and amortize generally utilizing the straight-line method over the term of the related debt. The straight-line method approximates the effective interest method and is consistent with the treatment in rates for regulated operations. We include the amortization expense in Interest Expense on our Consolidated Statements of Income.

Where reflected in rates, we include redemption premiums paid to reacquire preferred stock of utility subsidiaries in paid-in capital and amortize the premiums to retained earnings commensurate with recovery in rates. We credit the excess of par value over costs of preferred stock reacquired to paid-in capital and reclassify the excess to retained earnings upon the redemption of the entire preferred stock series.

Goodwill and Intangible Assets

When we acquire businesses, we record the fair value of all assets and liabilities, including intangible assets. To the extent that consideration exceeds the fair value of identified assets, we record goodwill. We do not amortize goodwill and intangible assets with indefinite lives. We test acquired goodwill and other intangible assets with indefinite lives for impairment at least annually at their estimated fair value. We test goodwill at the reporting unit level and other intangibles at the asset level. Fair value is the amount at which an asset or liability could be bought or sold in a current transaction between willing parties, that is, other than in a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, we estimate fair value using various internal and external valuation methods. We amortize intangible assets with finite lives over their respective estimated lives, currently 10 years, to their estimated residual values. We also review the lives of the amortizable intangibles with finite lives on an annual basis.

Investments Held in Trust for Future Liabilities

We have several trust funds with significant investments intended to provide for future payments of pension and OPEB benefits, nuclear decommissioning and spent nuclear fuel disposal. All of our trust funds' investments are diversified and managed in compliance with all laws and regulations. Our investment strategy for trust funds is to use a diversified portfolio of investments to achieve an acceptable rate of return while managing the interest rate sensitivity of the assets relative to the associated liabilities. To minimize investment risk, the trust funds are broadly diversified among classes of assets, investment strategies and investment managers. We regularly review the actual asset allocation and periodically rebalance the investments to targeted allocation when appropriate. Investment policies and guidelines allow investment managers in approved strategies to use financial derivatives to obtain or manage market exposures and to hedge assets and liabilities. The investments are reported at fair value under the "Fair Value Measurements and Disclosures" accounting guidance.

Benefit Plans

All benefit plan assets are invested in accordance with each plan's investment policy. The investment policy outlines the investment objectives, strategies and target asset allocations by plan.

The investment philosophies for our benefit plans support the allocation of assets to minimize risks and optimizing net returns. Strategies used include:

- Maintaining a long-term investment horizon.
- Diversifying assets to help control volatility of returns at acceptable levels.
- Managing fees, transaction costs and tax liabilities to maximize investment earnings.
- Using active management of investments where appropriate risk/return opportunities exist.
- Keeping portfolio structure style-neutral to limit volatility compared to applicable benchmarks.
- Using alternative asset classes such as real estate and private equity to maximize return and provide additional portfolio diversification.

The target asset allocation and allocation ranges are as follows:

Pension Plan Assets	Minimum	Target	Maximum
Domestic Equity	30.0 %	35.0 %	40.0 %
International and Global Equity	10.0 %	15.0 %	20.0 %
Fixed Income	35.0 %	39.0 %	45.0 %
Real Estate	4.0 %	5.0 %	6.0 %
Other Investments	1.0 %	5.0 %	7.0 %
Cash	0.5 %	1.0 %	3.0 %

OPEB Plans Assets	Minimum	Target	Maximum
Equity	61.0 %	66.0 %	71.0 %
Fixed Income	29.0 %	32.0 %	37.0 %
Cash	1.0 %	2.0 %	4.0 %

The investment policy for each benefit plan contains various investment limitations. The investment policies establish concentration limits for securities. Investment policies prohibit the benefit trust funds from purchasing securities issued by AEP (with the exception of proportionate and immaterial holdings of AEP securities in passive index strategies). However, our investment policies do not preclude the benefit trust funds from receiving contributions in the form of AEP securities, provided that the AEP securities acquired by each plan may not exceed the limitations imposed by law. Each investment manager's portfolio is compared to a diversified benchmark index.

For equity investments, the limits are as follows:

- No security in excess of 5% of all equities.
- Cash equivalents must be less than 10% of an investment manager's equity portfolio.
- Individual stock must be less than 10% of each manager's equity portfolio.
- No investment in excess of 5% of an outstanding class of any company.
- No securities may be bought or sold on margin or other use of leverage.

For fixed income investments, the concentration limits must not exceed:

- 3% in one issuer
- 20% in non-US dollar denominated
- 5% private placements
- 5% convertible securities
- 60% for bonds rated AA+ or lower
- 50% for bonds rated A+ or lower
- 10% for bonds rated BBB- or lower

For obligations of non-government issuers the following limitations apply:

- AAA rated debt: a single issuer should account for no more than 5% of the portfolio.
- AA+, AA, AA- rated debt: a single issuer should account for no more than 3% of the portfolio.
- Debt rated A+ or lower: a single issuer should account for no more than 2% of the portfolio.
- No more than 10% of the portfolio may be invested in high yield and emerging market debt combined at any time.

A portion of the pension assets is invested in real estate funds to provide diversification, add return and hedge against inflation. Real estate properties are illiquid, difficult to value and not actively traded. The pension plan uses external real estate investment managers to invest in commingled funds that hold real estate properties. To mitigate investment risk in the real estate portfolio, commingled real estate funds are used to ensure that holdings are diversified by region, property type and risk classification. Real estate holdings include core, value-added, and development risk classifications and some investments in Real Estate Investment Trusts (REITs), which are publicly traded real estate securities classified as Level 1.

A portion of the pension assets is invested in private equity. Private equity investments add return and provide diversification and typically require a long-term time horizon to evaluate investment performance. Private equity is classified as an alternative investment because it is illiquid, difficult to value and not actively traded. The pension plan uses limited partnerships and commingled funds to invest across the private equity investment spectrum. Our private equity holdings are with six general partners who help monitor the investments and provide investment selection expertise. The holdings are currently comprised of venture capital, buyout and hybrid debt and equity investment instruments. Commingled private equity funds are used to enhance the holdings' diversity.

We participate in a securities lending program with BNY Mellon to provide incremental income on idle assets and to provide income to offset custody fees and other administrative expenses. We lend securities to borrowers approved by BNY Mellon in exchange for cash collateral. All loans are collateralized by at least 102% of the loaned asset's market value and the cash collateral is invested. The difference between the rebate owed to the borrower and the cash collateral rate of return determines the earnings on the loaned security. The securities lending program's objective is providing modest incremental income with a limited increase in risk.

We hold trust owned life insurance (TOLI) underwritten by The Prudential Insurance Company in the OPEB plan trusts. The strategy for holding life insurance contracts in the taxable Voluntary Employees' Beneficiary Association (VEBA) trust is to minimize taxes paid on the asset growth in the trust. Earnings on plan assets are tax-deferred within the TOLI contract and can be tax-free if held until claims are paid. Life insurance proceeds remain in the trust and are used to fund future retiree medical benefit liabilities. With consideration to other investments held in the trust, the cash value of the TOLI contracts is invested in two diversified funds. A portion is invested in a commingled fund with underlying investments in stocks that are actively traded on major international equity exchanges. The other portion of the TOLI cash value is invested in a diversified, commingled fixed income fund with underlying investments in government bonds, corporate bonds and asset-backed securities.

Cash and cash equivalents are held in each trust to provide liquidity and meet short-term cash needs. Cash equivalent funds are used to provide diversification and preserve principal. The underlying holdings in the cash funds are investment grade money market instruments including commercial paper, certificates of deposit, treasury bills and other types of investment grade short-term debt securities. The cash funds are valued each business day and provide daily liquidity.

Nuclear Trust Funds

Nuclear decommissioning and spent nuclear fuel trust funds represent funds that regulatory commissions allow us to collect through rates to fund future decommissioning and spent nuclear fuel disposal liabilities. By rules or orders, the IURC, the MPSC and the FERC established investment limitations and general risk management guidelines. In general, limitations include:

- Acceptable investments (rated investment grade or above when purchased).
- Maximum percentage invested in a specific type of investment.
- Prohibition of investment in obligations of AEP or its affiliates.
- Withdrawals permitted only for payment of decommissioning costs and trust expenses.

We maintain trust records for each regulatory jurisdiction. The trust assets may not be used for another jurisdiction's liabilities. Regulatory approval is required to withdraw decommissioning funds. These funds are managed by external investment managers who must comply with the guidelines and rules of the applicable regulatory authorities. The trust assets are invested to optimize the net of tax earnings of the trust giving consideration to liquidity, risk, diversification and other prudent investment objectives.

We record securities held in these trust funds as Spent Nuclear Fuel and Decommissioning Trusts on our Consolidated Balance Sheets. We record these securities at fair value. We classify securities in the trust funds as available-for-sale due to their long-term purpose. Other-than-temporary impairments for investments in both debt and equity securities are considered realized losses as a result of securities being managed by an external investment management firm. The external investment management firm makes specific investment decisions regarding the equity and debt investments held in these trusts and generally intends to sell debt securities in an unrealized loss position as part of a tax optimization strategy. Impairments reduce the cost basis of the securities which will affect any future unrealized gain or realized gain or loss due to the adjusted cost of investment. We record unrealized gains and other-than-temporary impairments from securities in these trust funds as adjustments to the regulatory liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the spent nuclear fuel disposal trust funds in accordance with their treatment in rates. Consequently, changes in fair value of trust assets do not affect earnings or AOCI. See the "Nuclear Contingencies" section of Note 6 for additional discussion of nuclear matters. See "Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal" section of Note 11 for disclosure of the fair value of assets within the trusts.

Comprehensive Income (Loss)

Comprehensive income (loss) is defined as the change in equity (net assets) of a business enterprise during a period from transactions and other events and circumstances from nonowner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners. Comprehensive income (loss) has two components: net income (loss) and other comprehensive income (loss).

Components of Accumulated Other Comprehensive Income (Loss) (AOCI)

AOCI is included on our Consolidated Balance Sheets in our equity section. Our components of AOCI as of December 31, 2010 and 2009 are shown in the following table:

Components	December 31, 2010	December 31, 2009
	(in millions)	
Securities Available for Sale, Net of Tax	$ 4	$ 12
Cash Flow Hedges, Net of Tax	11	(15)
Amortization of Pension and OPEB Deferred Costs, Net of Tax	57	35
Pension and OPEB Funded Status, Net of Tax	(453)	(406)
Total	$ (381)	$ (374)

Stock-Based Compensation Plans

At December 31, 2010, we had stock options, performance units, restricted shares and restricted stock units outstanding under The Amended and Restated American Electric Power System Long-Term Incentive Plan (LTIP). This plan was last approved by shareholders in April 2010.

We maintain a variety of tax qualified and nonqualified deferred compensation plans for employees and non-employee directors that include, among other options, an investment in or an investment return equivalent to that of AEP common stock. This includes career share accounts maintained under the American Electric Power System Stock Ownership Requirement Plan, which facilitates executives in meeting minimum stock ownership requirements assigned to them by the HR Committee of the Board of Directors. Career shares are derived from vested performance units granted to employees under the LTIP. Career shares are equal in value to shares of AEP common stock and do not become payable to executives until after their service ends. Dividends paid on career shares are reinvested as additional career shares.

We compensate our non-employee directors, in part, with stock units under the American Electric Power Company, Inc. Stock Unit Accumulation Plan for Non-Employee Directors. These stock units become payable in cash to directors after their service ends.

In January 2006, we adopted accounting guidance for "Compensation - Stock Compensation" which requires the measurement and recognition of compensation expense for all share-based payment awards made to employees and directors, including stock options, based on estimated fair values.

We recognize compensation expense for all share-based awards with service only vesting conditions granted on or after January 2006 using the straight-line single-option method. Stock-based compensation expense recognized on our Consolidated Statements of Income for the years ended December 31, 2010, 2009 and 2008 is based on awards ultimately expected to vest. Therefore, stock-based compensation expense has been reduced to reflect estimated forfeitures. Accounting guidance for "Compensation - Stock Compensation" requires forfeitures to be estimated at the time of grant and revised, if necessary, in subsequent periods if actual forfeitures differ from those estimates.

For the years ended December 31, 2010, 2009 and 2008, compensation expense is included in Net Income for the performance units, career shares, restricted shares, restricted stock units and the non-employee director's stock units. See Note 15 for additional discussion.

Earnings Per Share (EPS)

Shown below are income statement amounts attributable to AEP common shareholders:

	Years Ended December 31,		
Amounts Attributable to AEP Common Shareholders	**2010**	**2009**	**2008**
		(in millions)	
Income Before Discontinued Operations and Extraordinary Loss	$ 1,211	$ 1,362	$ 1,368
Discontinued Operations, Net of Tax	-	-	12
Extraordinary Loss, Net of Tax	-	(5)	-
Net Income	$ 1,211	$ 1,357	$ 1,380

Basic earnings per common share is calculated by dividing net earnings available to common shareholders by the weighted average number of common shares outstanding during the period. Diluted earnings per common share is calculated by adjusting the weighted average outstanding common shares, assuming conversion of all potentially dilutive stock options and awards.

The following table presents our basic and diluted EPS calculations included on our Consolidated Statements of Income:

	Years Ended December 31,					
	2010		**2009**		**2008**	
	(in millions, except per share data)					
		$/share		**$/share**		**$/share**
Earnings Attributable to AEP Common Shareholders	$ 1,211		$ 1,357		$ 1,380	
Weighted Average Number of Basic Shares Outstanding	479.4	$ 2.53	458.7	$ 2.96	402.1	$ 3.43
Weighted Average Dilutive Effect of:						
Performance Share Units	0.1	-	0.3	-	1.2	0.01
Stock Options	-	-	-	-	0.1	-
Restricted Stock Units	0.1	-	-	-	0.1	-
Restricted Shares	-	-	-	-	0.1	-
Weighted Average Number of Diluted Shares Outstanding	479.6	$ 2.53	459.0	$ 2.96	403.6	$ 3.42

The assumed conversion of stock options does not affect net earnings for purposes of calculating diluted earnings per share.

Options to purchase 136,250, 452,216 and 470,016 shares of common stock were outstanding at December 31, 2010, 2009 and 2008, respectively, but were not included in the computation of diluted earnings per share attributable to AEP common shareholders. Since the options' exercise prices were greater than the average market price of the common shares, the effect would have been antidilutive.

CSPCo and OPCo Revised Depreciation Rates

Effective January 1, 2009, we revised book depreciation rates for CSPCo and OPCo generating plants consistent with a completed depreciation study. OPCo's overall higher depreciation rates primarily related to shortened depreciable lives for certain OPCo generating facilities. In comparing 2009 and 2008, the change in depreciation rates resulted in a net increase (decrease) in depreciation expense of:

	Depreciation Expense Variance Years Ended December 31, 2009/2008
	(in millions)
CSPCo	$ (18)
OPCo	71

The net change in depreciation rates resulted in a decrease to our net-of-tax, basic earnings per share of $0.08 for the year ended December 31, 2009.

Supplementary Information

Related Party Transactions	Years Ended December 31, 2010	2009	2008
		(in millions)	
AEP Consolidated Revenues – Utility Operations:			
Ohio Valley Electric Corporation (43.47% owned)	$ (20)(a)	$ -	$ (54)(b)
AEP Consolidated Revenues – Other Revenues:			
Ohio Valley Electric Corporation – Barging and Other Transportation Services (43.47% Owned)	29	31	32
AEP Consolidated Expenses – Purchased Electricity for Resale:			
Ohio Valley Electric Corporation (43.47% Owned)	302 (c)	286	263

(a) The AEP Power Pool purchased power from OVEC to serve off-system sales in an agreement that began in January 2010 and ended in June 2010.
(b) The AEP Power Pool purchased power from OVEC as part of risk management activities in an agreement that ended in December 2008.
(c) The AEP Power Pool purchased power from OVEC to serve retail sales in an agreement that began in January 2010 and ended in June 2010. The total amount reported in 2010 includes $10 million related to this agreement.

Cash Flow Information	Years Ended December 31, 2010	2009	2008
		(in millions)	
Cash Paid (Received) for:			
Interest, Net of Capitalized Amounts	$ 958	$ 924	$ 853
Income Taxes	(268)	(98)	233
Noncash Investing and Financing Activities:			
Acquisitions Under Capital Leases	225	86	62
Assumption of Liabilities Related to Acquisitions	8	-	-
Government Grants Included in Accounts Receivable at December 31,	10	-	-
Construction Expenditures Included in Accounts Payable at December 31,	267	348	460
Acquisition of Nuclear Fuel Included in Accounts Payable at December 31,	-	-	38
Noncash Donation Expense Related to Issuance of Treasury Shares to AEP Foundation	-	-	40

Transmission Investments

We participate in certain joint ventures which involve the development, construction, ownership and operation of transmission facilities. These investments are recorded using the equity method and reported as Deferred Charges and Other Noncurrent Assets on our Consolidated Balance Sheets.

Adjustments to Securitized Accounts Receivable Disclosure

In the "Securitized Accounts Receivable – AEP Credit" section of Note 14, we expanded our disclosure to reflect certain prior period amounts related to our securitization agreement that were not previously disclosed. These omissions were not material to our financial statements and had no impact on our previously reported net income, changes in shareholders' equity, financial position or cash flows.

2. NEW ACCOUNTING PRONOUNCEMENTS AND EXTRAORDINARY ITEM

NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of final pronouncements, we review the new accounting literature to determine its relevance, if any, to our business. The following represents a summary of final pronouncements that impact our financial statements.

Pronouncements Adopted During 2010

The following standards were effective during 2010. Consequently, their impact is reflected in the financial statements. The following paragraphs discuss their impact.

ASU 2009-16 "Transfers and Servicing" (ASU 2009-16)

In 2009, the FASB issued ASU 2009-16 clarifying when a transfer of a financial asset should be recorded as a sale. The standard defines participating interest to establish specific conditions for a sale of a portion of a financial asset. This standard must be applied to all transfers after the effective date.

We adopted ASU 2009-16 effective January 1, 2010. AEP Credit securitizes an interest in receivables it acquires from certain of its affiliates to bank conduits and receives cash. As of December 31, 2009, AEP Credit owed $656 million to bank conduits related to receivable sales outstanding. Upon adoption of ASU 2009-16, future transactions do not constitute a sale of receivables and are accounted for as financings. Effective January 2010, we record the receivables and related debt on our Consolidated Balance Sheet.

ASU 2009-17 "Consolidations" (ASU 2009-17)

In 2009, the FASB issued ASU 2009-17 amending the analysis an entity must perform to determine if it has a controlling financial interest in a VIE. In addition to presentation and disclosure guidance, ASU 2009-17 provides that the primary beneficiary of a VIE must have both:

- The power to direct the activities of the VIE that most significantly impact the VIE's economic performance.
- The obligation to absorb the losses of the entity that could potentially be significant to the VIE or the right to receive benefits from the entity that could potentially be significant to the VIE.

We adopted the prospective provisions of ASU 2009-17 effective January 1, 2010 and deconsolidated DHLC. DHLC was deconsolidated due to the shared control between SWEPCo and CLECO. After January 1, 2010, we report DHLC using the equity method of accounting.

This standard increased our disclosure requirements for AEP Credit and Transition Funding, wholly-owned consolidated subsidiaries. See "Variable Interest Entities" section of Note 1 for further discussion.

EXTRAORDINARY ITEM

SWEPCo Texas Restructuring

In August 2006, the PUCT adopted a rule extending the delay in implementation of customer choice in SWEPCo's SPP area of Texas until no sooner than January 1, 2011. In May 2009, the governor of Texas signed a bill related to SWEPCo's SPP area of Texas that requires continued cost of service regulation until certain stages have been completed and approved by the PUCT such that fair competition is available to all Texas retail customer classes. Based upon the signing of the bill, SWEPCo re-applied "Regulated Operations" accounting guidance for the generation portion of SWEPCo's Texas retail jurisdiction effective second quarter of 2009. Management believes that a return to competition in the SPP area of Texas will not occur. The reapplication of "Regulated Operations" accounting guidance resulted in an $8 million ($5 million, net of tax) extraordinary loss.

3. GOODWILL AND OTHER INTANGIBLE ASSETS

Goodwill

The changes in our carrying amount of goodwill for the years ended December 31, 2010 and 2009 by operating segment are as follows:

	Utility Operations	AEP River Operations (in millions)	AEP Consolidated
Balance at December 31, 2008	$ 37	$ 39	$ 76
Impairment Losses	-	-	-
Balance at December 31, 2009	37	39	76
Impairment Losses	-	-	-
Balance at December 31, 2010	$ 37	$ 39	$ 76

In the fourth quarters of 2010 and 2009, we performed our annual impairment tests. The fair values of the operations with goodwill were estimated using cash flow projections and other market value indicators. There were no goodwill impairment losses. We do not have any accumulated impairment on existing goodwill.

Other Intangible Assets

Acquired intangible assets subject to amortization were $1.2 million and $10.3 million at December 31, 2010 and 2009, respectively, net of accumulated amortization and are included in Deferred Charges and Other Noncurrent Assets on our Consolidated Balance Sheets. The amortization life, gross carrying amount and accumulated amortization by major asset class are as follows:

		December 31,			
		2010		2009	
	Amortization Life	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
	(in years)	(in millions)			
Easements	10	$ 2.2	$ 2.2	$ 2.2	$ 1.9
Purchased Technology	10	10.9	9.7	10.9	8.6
Advanced Royalties	15	-	-	29.4	21.7
Total		$ 13.1	$ 11.9	$ 42.5	$ 32.2

Amortization of intangible assets was $1 million, $3 million and $3 million for 2010, 2009 and 2008, respectively. Our estimated total amortization is $1 million for 2011 and $138 thousand for 2012.

The Advanced Royalties asset class relates to the lignite mine of DHLC, a wholly-owned subsidiary of SWEPCo. As of January 1, 2010, SWEPCo no longer consolidates DHLC, but rather it is reported as an equity investment, resulting in the elimination of a review of this asset by SWEPCo. Also, see "ASU 2009-17 'Consolidations'" section of Note 2 for discussion of impact of new accounting guidance effective January 1, 2010.

Other than goodwill, we have no intangible assets that are not subject to amortization.

4. RATE MATTERS

Our subsidiaries are involved in rate and regulatory proceedings at the FERC and their state commissions. Rate matters can have a material impact on net income, cash flows and possibly financial condition. Our recent significant rate orders and pending rate filings are addressed in this note.

CSPCo and OPCo Rate Matters

Ohio Electric Security Plan Filings

2009 – 2011 ESPs

The PUCO issued an order in March 2009 that modified and approved CSPCo's and OPCo's ESPs which established rates at the start of the April 2009 billing cycle. The ESPs are in effect through 2011. The order also limited annual rate increases for CSPCo to 7% in 2009, 6% in 2010 and 6% in 2011 and for OPCo to 8% in 2009, 7% in 2010 and 8% in 2011. Some rate components and increases are exempt from these limitations. CSPCo and OPCo collected the 2009 annualized revenue increase over the last nine months of 2009.

The order provided a FAC for the three-year period of the ESP. The FAC was phased in to avoid having the resultant rate increases exceed the ordered annual caps described above. The FAC is subject to quarterly true-ups, annual accounting audits and prudency reviews. See the "2009 Fuel Adjustment Clause Audit" section below. The order allowed CSPCo and OPCo to defer any unrecovered FAC costs resulting from the annual caps and accrued associated carrying charges at CSPCo's and OPCo's weighted average cost of capital. Any deferred FAC regulatory asset balance at the end of the three-year ESP period will be recovered through a non-bypassable surcharge over the period 2012 through 2018. That recovery will include deferrals associated with the Ormet interim arrangement and is subject to the PUCO's ultimate decision regarding the Ormet interim arrangement deferrals plus related carrying charges. See the "Ormet Interim Arrangement" section below. The FAC deferral as of December 31, 2010 was $476 million for OPCo excluding $30 million of unrecognized equity carrying costs.

Discussed below are the significant outstanding uncertainties related to the ESP order:

The Ohio Consumers' Counsel filed a notice of appeal with the Supreme Court of Ohio raising several issues including alleged retroactive ratemaking, recovery of carrying charges on certain environmental investments, Provider of Last Resort (POLR) charges and the decision not to offset rates by off-system sales margins. A decision from the Supreme Court of Ohio is pending.

In November 2009, the Industrial Energy Users-Ohio filed a notice of appeal with the Supreme Court of Ohio challenging components of the ESP order including the POLR charge, the distribution riders for gridSMART® and enhanced reliability, the PUCO's conclusion and supporting evaluation that the modified ESPs are more favorable than the expected results of a market rate offer, the unbundling of the fuel and non-fuel generation rate components, the scope and design of the fuel adjustment clause and the approval of the plan after the 150-day statutory deadline. A decision from the Supreme Court of Ohio is pending.

In April 2010, the Industrial Energy Users-Ohio filed an additional notice of appeal with the Supreme Court of Ohio challenging alleged retroactive ratemaking, CSPCo's and OPCo's abilities to collect through the FAC amounts deferred under the Ormet interim arrangement and the approval of the plan after the 150-day statutory deadline. A decision from the Supreme Court of Ohio is pending.

Ohio law requires that the PUCO determine, following the end of each year of the ESP, if rate adjustments included in the ESP resulted in significantly excessive earnings under the Significantly Excessive Earnings Test (SEET). If the rate adjustments, in the aggregate, result in significantly excessive earnings, the excess amount could be returned to customers. In September 2010, CSPCo and OPCo filed their 2009 SEET filings with the PUCO. CSPCo's and OPCo's returns on common equity were 20.84% and 10.81%, respectively, including off-system sales margins. In January 2011, the PUCO issued an order that determined a return on common equity for 2009 in excess of 17.6% would be significantly excessive. The PUCO determined that OPCo's 2009 earnings were not significantly excessive but determined relevant CSPCo earnings, excluding off-system sales margins, to be 19.73%, which exceeded the PUCO determined threshold by 2.13%. As a result, the PUCO ordered CSPCo to refund $43 million ($28 million net of tax) of its earnings to customers, which was recorded as a revenue provision on CSPCo's December 2010 books. The PUCO ordered that the significantly excessive earnings be applied first to CSPCo's FAC deferral, including unrecognized equity carrying costs, as of the date of the order, with any remaining balance to be credited to CSPCo's customers on a per kilowatt basis which began with the first billing cycle in February 2011 through December 2011. Several parties, including CSPCo and OPCo, have filed requests for rehearing with the PUCO, which remain pending. CSPCo and OPCo are required to file their 2010 SEET filing with the PUCO in 2011. Based upon the approach in the PUCO 2009 order, management does not currently believe that there are significantly excessive earnings in 2010.

Management is unable to predict the outcome of the various ongoing ESP proceedings and litigation discussed above. If these proceedings, including future SEET filings, result in adverse rulings, it could reduce future net income and cash flows and impact financial condition.

Proposed January 2012 – May 2014 ESP

In January 2011, CSPCo and OPCo filed an application with the PUCO to approve a new ESP that includes a standard service offer (SSO) pricing on a combined company basis for generation effective with the first billing cycle of January 2012 through the last billing cycle of May 2014. The ESP also includes alternative energy resource requirements and addresses provisions regarding distribution service, energy efficiency requirements, economic development, job retention in Ohio and other matters. The SSO presents redesigned generation rates by customer class. Customer class rates individually vary, but on average, customers will experience net base generation increases of 1.4% in 2012 and 2.7% for the period January 2013 through May 2014.

Proposed CSPCo and OPCo Merger

In October 2010, CSPCo and OPCo filed an application with the PUCO to merge CSPCo into OPCo. Approval of the merger will not affect CSPCo's and OPCo's rates until such time as the PUCO approves new rates, terms and conditions for the merged company. In January 2011, CSPCo and OPCo filed an application with the FERC requesting approval for an internal corporate reorganization under which CSPCo will merge into OPCo. CSPCo and OPCo requested the reorganization transaction be effective in October 2011. Decisions are pending from the PUCO and the FERC.

Requested Sporn Unit 5 Shutdown and Proposed Distribution Rider

In October 2010, OPCo filed an application with the PUCO for the approval of a December 2010 closure of Sporn Unit 5 and the simultaneous establishment of a new non-bypassable distribution rider, outside the rate caps established in the 2009 – 2011 ESP proceeding. The proposed rider would recover the net book value of the unit as well as related materials and supplies as of December 2010, which is estimated to be $59 million, as well as future closure costs incurred after December 2010. OPCo also requested authority to record the future closure costs as a regulatory asset or regulatory liability with a weighted average cost of capital carrying charge to be included in the proposed non-bypassable distribution rider after they are incurred. Also in October 2010, OPCo filed a retirement notification with PJM pending PUCO approval of OPCo's application to close Sporn Unit 5, which was granted by PJM. Pending PUCO approval, Sporn Unit 5 continues to operate. Management is unable to predict the outcome of this proceeding.

2009 Fuel Adjustment Clause Audit

As required under the ESP orders, the PUCO selected an outside consultant to conduct the audit of the FAC for the period of January 2009 through December 2009. In May 2010, the outside consultant provided their confidential audit report to the PUCO. The audit report included a recommendation that the PUCO should review whether any proceeds from a 2008 coal contract settlement agreement which totaled $72 million should reduce OPCo's FAC under-recovery balance. Of the total proceeds, approximately $58 million was recognized as a reduction to fuel expense prior to 2009 and $14 million reduced fuel expense in 2009 and 2010. Hearings were held in August 2010. If the PUCO orders any portion of the $58 million previously recognized or potential other future adjustments be used to reduce the current year FAC deferral, it would reduce future net income and cash flows and impact financial condition.

Ormet Interim Arrangement

CSPCo, OPCo and Ormet, a large aluminum company, filed an application with the PUCO for approval of an interim arrangement governing the provision of generation service to Ormet. This interim arrangement was approved by the PUCO and was effective from January 2009 through September 2009. In March 2009, the PUCO approved a FAC in the ESP filings. The approval of the FAC, together with the PUCO approval of the interim arrangement, provided the basis to record regulatory assets for the difference between the approved market price and the rate paid by Ormet. The Industrial Energy Users-Ohio, CSPCo and OPCo filed Notices of Appeal regarding aspects of this decision with the Supreme Court of Ohio. A hearing at the Supreme Court of Ohio was held in February 2011. Through September 2009, the last month of the interim arrangement, CSPCo and OPCo had $30 million and $34 million, respectively, of deferred FAC related to the interim arrangement including recognized carrying charges. These amounts exclude $1 million and $1 million, respectively, of unrecognized equity carrying costs. In November 2009, CSPCo and OPCo requested that the PUCO approve recovery of the deferrals under the interim agreement plus a weighted average cost of capital carrying charge. The interim arrangement deferrals are included in CSPCo's and OPCo's FAC phase-in deferral balances. See "Ohio Electric Security Plan Filings" section above. In the ESP proceeding, intervenors requested that CSPCo and OPCo be required to refund the Ormet-related regulatory assets and requested that the PUCO prevent CSPCo and OPCo from collecting the Ormet-related revenues in the future. The PUCO did not take any action on this request in the ESP proceeding. The intervenors raised the issue again in response to CSPCo's and OPCo's November 2009 filing to approve recovery of the deferrals under the interim agreement. If CSPCo and OPCo are not ultimately permitted to fully recover their requested deferrals under the interim arrangement, it would reduce future net income and cash flows and impact financial condition.

Economic Development Rider

In April 2010, the Industrial Energy Users-Ohio filed a notice of appeal of the 2009 PUCO-approved Economic Development Rider (EDR) with the Supreme Court of Ohio. The EDR collects from ratepayers the difference between the standard tariff and lower contract billings to qualifying industrial customers, subject to PUCO approval. The Industrial Energy Users-Ohio raised several issues including claims that (a) the PUCO lost jurisdiction over CSPCo's and OPCo's ESP proceedings and related proceedings when the PUCO failed to issue ESP orders within the 150-day statutory deadline, (b) the EDR should not be exempt from the ESP annual rate limitations and (c) CSPCo and OPCo should not be allowed to apply a weighted average long-term debt carrying cost on deferred EDR regulatory assets.

In June 2010, Industrial Energy Users-Ohio filed a notice of appeal of the 2010 PUCO-approved EDR with the Supreme Court of Ohio. The Industrial Energy Users-Ohio raised the same issues as noted in the 2009 EDR appeal plus a claim that CSPCo and OPCo should not be able to take the benefits of the higher ESP rates while simultaneously challenging the ESP orders.

As of December 31, 2010, CSPCo and OPCo have incurred $38 million and $30 million, respectively, in EDR costs including carrying costs. Of these costs, CSPCo and OPCo have collected $35 million and $26 million, respectively, through the EDR, which CSPCo and OPCo began collecting in January 2010. The remaining $3 million and $4 million for CSPCo and OPCo, respectively, are recorded as EDR regulatory assets. If CSPCo and OPCo are not ultimately permitted to recover their deferrals or are required to refund revenue collected, it would reduce future net income and cash flows and impact financial condition.

Environmental Investment Carrying Cost Rider

In February 2010, CSPCo and OPCo filed an application with the PUCO to establish an Environmental Investment Carrying Cost Rider to recover carrying costs for 2009 through 2011 related to environmental investments made in 2009. The carrying costs include both a return of and on the environmental investments as well as related administrative and general expenses and taxes. In August 2010, the PUCO issued an order approving a rider of approximately $26 million and $34 million for CSPCo and OPCo, respectively, effective September 2010. The implementation of the rider will likely not impact cash flows since this rider is subject to the rate increase caps authorized by the PUCO in the ESP proceedings, but will increase the ESP phase-in plan deferrals associated with the FAC.

Ohio IGCC Plant

In March 2005, CSPCo and OPCo filed a joint application with the PUCO seeking authority to recover costs of building and operating an IGCC power plant. Through December 31, 2010, CSPCo and OPCo have each collected $12 million in pre-construction costs authorized in a June 2006 PUCO order and each incurred $11 million in pre-construction costs. As a result, CSPCo and OPCo each established a net regulatory liability of approximately $1 million. The order also provided that if CSPCo and OPCo have not commenced a continuous course of construction of the proposed IGCC plant before June 2011, all pre-construction costs that may be utilized in projects at other sites must be refunded to Ohio ratepayers with interest. Intervenors have filed motions with the PUCO requesting all pre-construction costs be refunded to Ohio ratepayers with interest.

CSPCo and OPCo will not start construction of an IGCC plant until existing statutory barriers are addressed and sufficient assurance of regulatory cost recovery exists. Management cannot predict the outcome of any cost recovery litigation concerning the Ohio IGCC plant or what effect, if any, such litigation would have on future net income and cash flows. However, if CSPCo and OPCo were required to refund all or some of the pre-construction costs collected and the costs incurred were not recoverable in another jurisdiction, it would reduce future net income and cash flows and impact financial condition.

SWEPCo Rate Matters

Turk Plant

SWEPCo is currently constructing the Turk Plant, a new base load 600 MW pulverized coal ultra-supercritical generating unit in Arkansas, which is expected to be in service in 2012. SWEPCo owns 73% (440 MW) of the Turk Plant and will operate the completed facility. The Turk Plant is currently estimated to cost $1.7 billion, excluding AFUDC, plus an additional $125 million for transmission, excluding AFUDC. SWEPCo's share is currently estimated to cost $1.3 billion, excluding AFUDC, plus the additional $125 million for transmission, excluding AFUDC. As of December 31, 2010, excluding costs attributable to its joint owners, SWEPCo has capitalized approximately $1 billion of expenditures (including AFUDC and capitalized interest of $137 million and related transmission costs of $66 million). As of December 31, 2010, the joint owners and SWEPCo have contractual construction commitments of approximately $321 million (including related transmission costs of $3 million). SWEPCo's share of the contractual construction commitments is $235 million. If the plant is cancelled, the joint owners and SWEPCo would incur contractual construction cancellation fees, based on construction status as of December 31, 2010, of approximately $121 million (including related transmission cancellation fees of $1 million). SWEPCo's share of the contractual construction cancellation fees would be approximately $89 million.

Discussed below are the significant outstanding uncertainties related to the Turk Plant:

The APSC granted approval for SWEPCo to build the Turk Plant by issuing a Certificate of Environmental Compatibility and Public Need (CECPN) for the 88 MW SWEPCo Arkansas jurisdictional share of the Turk Plant. Following an appeal by certain intervenors, the Arkansas Supreme Court issued a decision that reversed the APSC's grant of the CECPN. The Arkansas Supreme Court ultimately concluded that the APSC erred in determining the need for additional power supply resources in a proceeding separate from the proceeding in which the APSC granted the CECPN. However, the Arkansas Supreme Court approved the APSC's procedure of granting CECPNs for transmission facilities in dockets separate from the Turk Plant CECPN proceeding. SWEPCo filed a notice with the APSC of its intent to proceed with construction of the Turk Plant but that SWEPCo no longer intends to pursue a CECPN to seek recovery of the originally approved 88 MW portion of Turk Plant costs in Arkansas retail rates. In June 2010, the APSC issued an order which reversed and set aside the previously granted CECPN.

The PUCT issued an order approving a Certificate of Convenience and Necessity (CCN) for the Turk Plant with the following conditions: (a) a cap on the recovery of jurisdictional capital costs for the Turk Plant based on the previously estimated $1.522 billion projected construction cost, excluding AFUDC and related transmission costs, (b) a cap on recovery of annual CO_2 emission costs at $28 per ton through the year 2030 and (c) a requirement to hold Texas ratepayers financially harmless from any adverse impact related to the Turk Plant not being fully subscribed to by other utilities or wholesale customers. SWEPCo appealed the PUCT's order contending the two cost cap restrictions are unlawful. The Texas Industrial Energy Consumers filed an appeal contending that the PUCT's grant of a conditional CCN for the Turk Plant was unnecessary to serve retail customers. In February 2010, the Texas District Court affirmed the PUCT's order in all respects. In March 2010, SWEPCo and the Texas Industrial Energy Consumers appealed this decision to the Texas Court of Appeals.

The LPSC approved SWEPCo's application to construct the Turk Plant. The Sierra Club filed a complaint with the LPSC to begin an investigation into the construction of the Turk Plant. In November 2010, the LPSC dismissed the complaint.

In November 2008, SWEPCo received its required air permit approval from the Arkansas Department of Environmental Quality and commenced construction at the site. The Arkansas Pollution Control and Ecology Commission (APCEC) upheld the air permit. The parties who unsuccessfully appealed the air permit to the APCEC filed a notice of appeal with the Circuit Court of Hempstead County, Arkansas. In December 2010, the Circuit Court affirmed the APCEC. In January 2011, the same parties asked the Arkansas Court of Appeals to overturn the Circuit Court's December 2010 decision. A decision from the Arkansas Court of Appeals is pending.

A wetlands permit was issued by the U.S. Army Corps of Engineers in December 2009. In 2010, the Sierra Club, the Audubon Society and others filed a complaint in the Federal District Court for the Western District of Arkansas against the U.S. Army Corps of Engineers challenging the process used and the terms of the permit issued to SWEPCo authorizing certain wetland and stream impacts, and sought a preliminary injunction to halt construction and for a temporary restraining order. In July 2010, the Hempstead County Hunting Club also filed a complaint with the Federal District Court for the Western District of Arkansas against SWEPCo, the U.S. Army Corps of Engineers, the U.S. Department of the Interior and the U.S. Fish and Wildlife Service seeking a temporary restraining order and preliminary injunction to stop construction of the Turk Plant asserting claims of violations of federal and state laws. The plaintiffs' federal law claims challenge the process used and terms of the permit issued to SWEPCo authorizing certain wetland and stream impacts. The plaintiffs' state law claims challenge SWEPCo's ability to construct the Turk Plant without obtaining a certificate from the APSC. In 2010, the motions for preliminary injunction were partially granted and upheld on appeal pending a hearing. According to the preliminary injunction, all uncompleted construction work associated with wetlands, streams or rivers at the Turk Plant must immediately stop. Mitigation measures required by the permit are authorized and may be completed. The preliminary injunction affects portions of the water intake and associated piping and portions of the transmission lines. A hearing on SWEPCo's appeal is scheduled for March 2011. In October 2010, the Federal District Court certified issues relating to the state law claims to the Arkansas Supreme Court, including whether those claims are within the primary jurisdiction of the APSC. The Arkansas Supreme Court accepted the request.

In January 2009, SWEPCo was granted CECPNs by the APSC to build three transmission lines and facilities authorized by the SPP and needed to transmit power from the Turk Plant. Intervenors appealed the CECPN decisions in April 2009 to the Arkansas Court of Appeals. In July 2010, the Hempstead County Hunting Club and other appellants filed with the Arkansas Court of Appeals emergency motions to stay the transmission CECPNs to prohibit SWEPCo from taking ownership of private property and undertaking construction of the transmission lines. The Arkansas Court of Appeals issued a decision in July 2010 remanding all transmission line CECPN appeals to the APSC. As a result, a stay was not ordered and construction continues on the affected transmission lines. In January 2011, the appellants filed requests to withdraw their appeals at the Court of Appeals and the APSC postponed a scheduled hearing pending a ruling on those requests. In February 2011, the Court of Appeals dismissed the appeals, and the APSC subsequently closed the remand docket, finding the CECPN decisions final and non-appealable. As previously discussed, the preliminary injunction issued by the Federal District Court related to the wetlands permit also impacts the uncompleted construction on portions of the transmission lines.

Management expects that SWEPCo will ultimately be able to complete construction of the Turk Plant and related transmission facilities and place those facilities in service. However, if SWEPCo is unable to complete the Turk Plant construction, including the related transmission facilities, and place the Turk Plant in service or if SWEPCo cannot recover all of its investment in and expenses related to the Turk Plant, it would materially reduce future net income and cash flows and materially impact financial condition.

Stall Unit

SWEPCo constructed the Stall Unit, an intermediate load 500 MW natural gas-fired combustion turbine combined cycle generating unit, at its existing Arsenal Hill Plant located in Shreveport, Louisiana. The LPSC and the APSC issued orders capping SWEPCo's Stall Unit construction costs at $445 million including AFUDC and excluding related transmission costs. The Stall Unit was placed in service in June 2010. As of December 31, 2010, the Stall Unit cost applicable to the cap was $426 million, including $49 million of AFUDC. Management does not expect the final costs of the Stall Unit to exceed the ordered cap. In July 2010, the Stall Unit was placed into Arkansas rates. SWEPCo received CWIP treatment for a portion of the Stall Unit in the 2009 Texas Base Rate Filing. See "2009 Texas Base Rate Filing" section below. The Stall Unit will be phased into Louisiana rates between October 2010 and October 2011.

2009 Texas Base Rate Filing

In August 2009, SWEPCo filed a rate case with the PUCT to increase its base rates by approximately $75 million annually including a return on common equity of 11.5%. The filing included requests for financing cost riders of $32 million related to construction of the Stall Unit and Turk Plant, a vegetation management rider of $16 million and other requested increases of $27 million. In April 2010, a settlement agreement was approved by the PUCT to increase SWEPCo's base rates by approximately $15 million annually, effective May 2010, including a return on common equity of 10.33%, which consists of $5 million related to construction of the Stall Unit and $10 million in other increases. In addition, the settlement agreement decreased annual depreciation expense by $17 million and allowed SWEPCo a $10 million one-year surcharge rider to recover additional vegetation management costs that SWEPCo must spend within two years.

Texas Fuel Reconciliation

In May 2010, various intervenors, including the PUCT staff, filed testimony recommending disallowances ranging from $3 million to $30 million in SWEPCo's $755 million fuel and purchased power costs reconciliation for the period January 2006 through March 2009. In July 2010, Cities Advocating Reasonable Deregulation filed testimony regarding the 2007 transfer of ERCOT trading contracts to AEPEP. The testimony included unquantified refund recommendations relating to re-pricing of contract transactions.

In September 2010, the Administrative Law Judges issued a Proposal for Decision (PFD) that recommended a disallowance of a significant portion of the charges under a ten-year gas transportation agreement that began in 2009 for the Mattison Plant located in northwest Arkansas. In January 2011, the PUCT issued an order which overturned a portion of the PFD that recommended a finding of imprudence on the Mattison gas contract. The impact of this order had an immaterial impact on SWEPCo's financial statements.

TCC and TNC Rate Matters

TEXAS RESTRUCTURING

Texas Restructuring Appeals

Pursuant to PUCT restructuring orders, TCC securitized net recoverable stranded generation costs of $2.5 billion and is recovering the principal and interest on the securitization bonds through the end of 2020. TCC also refunded other net true-up regulatory liabilities of $375 million during the period October 2006 through June 2008 via a CTC credit rate rider under PUCT restructuring orders. TCC and intervenors appealed the PUCT's true-up related orders. After rulings from the Texas District Court and the Texas Court of Appeals, TCC, the PUCT and intervenors filed petitions for review with the Texas Supreme Court. Review is discretionary and the Texas Supreme Court has not yet determined if it will grant review. The Texas Supreme Court requested a full briefing which has concluded. The following represent issues where either the Texas District Court or the Texas Court of Appeals recommended the PUCT decision be modified:

- The Texas District Court judge determined that the PUCT erred by applying an invalid rule to determine the carrying cost rate for the true-up of stranded costs. The Texas Court of Appeals reversed the District Court's unfavorable decision. An October 2010 decision of the Texas Supreme Court addressing the same issue for another utility upholds the Court of Appeals determination.

- The Texas District Court judge determined that the PUCT improperly reduced TCC's net stranded plant costs for commercial unreasonableness. This favorable decision was affirmed by the Texas Court of Appeals.

- The Texas Court of Appeals determined that the PUCT erred by not reducing stranded costs by the "excess earnings" that had already been refunded to affiliated Retail Electric Providers (REPs). This decision could be unfavorable unless the PUCT allows TCC to recover the refunds previously made to the REPs. See the "TCC Excess Earnings" section below.

Management cannot predict the outcome of the pending court proceedings and the PUCT remand decisions. If TCC ultimately succeeds in its appeals, it could have a favorable effect on future net income, cash flows and possibly financial condition. If intervenors succeed in their appeals, it could reduce future net income and cash flows and possibly impact financial condition.

TCC Deferred Investment Tax Credits and Excess Deferred Federal Income Taxes

In 2006, the PUCT reduced recovery of the amount securitized by $103 million of tax benefits and associated carrying costs related to TCC's generation assets. In 2006, TCC obtained a private letter ruling from the IRS which confirmed that such reduction was an IRS normalization violation. In order to avoid a normalization violation, the PUCT agreed to allow TCC to defer refunding the tax benefits of $103 million plus interest through the CTC refund period pending resolution of the normalization issue. In 2008, the IRS issued final regulations, which supported the IRS' private letter ruling which would make the refunding of or the reduction of the amount securitized by such tax benefits a normalization violation. After the IRS issued its final regulations, at the request of the PUCT, the Texas Court of Appeals remanded the tax normalization issue to the PUCT for the consideration of additional evidence including the IRS regulations. TCC is not accruing interest on the $103 million because it is not probable that the PUCT will order TCC to violate the normalization provision of the Internal Revenue Code. If interest were accrued, management estimates interest expense would have been approximately $22 million higher for the period July 2008 through December 2010.

Management believes that the PUCT will ultimately allow TCC to retain the deferred amounts, which would have a favorable effect on future net income and cash flows. Although unexpected, if the PUCT fails to issue a favorable order and orders TCC to return the tax benefits to customers, the resulting normalization violation could result in TCC's repayment to the IRS of Accumulated Deferred Investment Tax Credits (ADITC) on all property, including transmission and distribution property. This amount approximates $101 million as of December 31, 2010. It could also lead to a loss of TCC's right to claim accelerated tax depreciation in future tax returns. If TCC is required to repay its ADITC to the IRS and is also required to refund ADITC plus unaccrued interest to customers, it would reduce future net income and cash flows and impact financial condition.

TCC Excess Earnings

In 2005, a Texas appellate court issued a decision finding that a PUCT order requiring TCC to refund to the Retail Electric Providers (REPs) excess earnings prior to and outside of the true-up process was unlawful under the Texas Restructuring Legislation. From 2002 to 2005, TCC refunded $55 million of excess earnings, including interest, under the overturned PUCT order. On remand, the PUCT must determine how to implement the Court of Appeals decision given that the unauthorized refunds were made to the REPs in lieu of reducing stranded costs in the true-up proceeding.

Certain parties have taken positions that, if adopted, could result in TCC being required to refund excess earnings and interest through the true-up process without receiving a refund from the REPs. If this were to occur, it would reduce future net income and cash flows and impact financial condition. Management cannot predict the outcome of the excess earnings remand.

OTHER TEXAS RATE MATTERS

Texas Base Rate Appeal

TCC filed a base rate case in 2006 seeking to increase base rates. The PUCT issued an order in 2007 which increased TCC's base rates by $20 million, eliminated a merger credit rider of $20 million and reduced depreciation rates by $7 million. The PUCT decision was appealed by TCC and various intervenors. On appeal, the Texas District Court affirmed the PUCT in most respects and the Texas Court of Appeals affirmed the Texas District Court's decision. The order became final with an August 2010 Texas Court of Appeals mandate.

ETT 2007 Formation Appeal

ETT is a joint venture between AEP Utilities, Inc. and MidAmerican Energy Holdings Company Texas Transco, LLC. TCC and TNC have sold transmission assets both in service and under construction to ETT. The PUCT approved ETT's initial rates, a request for a transfer of in-service assets and CWIP and a certificate of convenience and necessity (CCN) to operate as a stand alone transmission utility in ERCOT. ETT was allowed a 9.96% return on common equity. Intervenors appealed the PUCT's decision but the Texas Court of Appeals affirmed the PUCT's decision in all material respects. The deadline to appeal this decision to the Texas Supreme Court has expired.

In a separate development, the Texas governor signed a new law that clarifies the PUCT's authority to grant CCNs to transmission only utilities such as ETT. ETT filed an application with the PUCT for a CCN under the new law. In March 2010, the PUCT approved the application for a CCN under the new law.

APCo and WPCo Rate Matters

2009 Virginia Base Rate Case

In July 2009, APCo filed a generation and distribution base rate increase with the Virginia SCC of $154 million annually based on a 13.35% return on common equity. Interim rates, subject to refund, became effective in December 2009 but were discontinued in February 2010 when newly enacted Virginia legislation suspended the collection of interim rates. In July 2010, the Virginia SCC issued an order approving a $62 million increase based on a 10.53% return on common equity. The order denied recovery of the Virginia share of the Mountaineer Carbon Capture and Storage Product Validation Facility, which resulted in a pretax write-off of $54 million in Other Operation. See "Mountaineer Carbon Capture and Storage Project" section below. In addition, the order allowed the deferral of approximately $25 million of incremental storm expense incurred in 2009. Approximately $3 million, including interest, was refunded to customers in September 2010 related to the collection of interim rates.

2010 West Virginia Base Rate Case

In May 2010, APCo and WPCo filed a request with the WVPSC to increase annual base rates by $156 million based on an 11.75% return on common equity to be effective March 2011. The filing also included a request for recovery of and a return on the West Virginia jurisdictional share of the Mountaineer Carbon Capture and Storage Product

Validation Facility. In December 2010, a settlement agreement was filed with the WVPSC to increase annual base rates by $60 million, effective March 2011. The settlement agreement allows APCo to defer and amortize up to $18 million of previously expensed 2009 incremental storm expenses over a period of eight years. A decision from the WVPSC is expected in March 2011.

Mountaineer Carbon Capture and Storage Project

Product Validation Facility (PVF)

APCo and ALSTOM Power, Inc., an unrelated third party, jointly constructed a CO_2 capture validation facility, which was placed into service in September 2009. APCo also constructed and owns the necessary facilities to store the CO_2. In October 2009, APCo started injecting CO_2 into the underground storage facilities. The injection of CO_2 required the recording of an asset retirement obligation and an offsetting regulatory asset. As of December 31, 2010, APCo has recorded a noncurrent regulatory asset of $60 million related to the PVF.

In APCo's July 2009 Virginia base rate filing, APCo requested recovery of and a return on its Virginia jurisdictional share of its project costs and recovery of the related asset retirement obligation regulatory asset amortization and accretion. In July 2010, the Virginia SCC issued a base rate order that denied recovery of the Virginia share of the PVF costs. See "2009 Virginia Base Rate Case" section above.

In APCo's and WPCo's May 2010 West Virginia base rate filing, APCo and WPCo requested recovery of and a return on their West Virginia jurisdictional share of the project costs and recovery of the related asset retirement obligation regulatory asset amortization and accretion. In December 2010, a settlement agreement was filed with the WVPSC to increase annual base rates by $60 million, effective March 2011. A decision from the WVPSC is expected in March 2011. If APCo cannot recover its remaining investment in and expenses related to the PVF, it would reduce future net income and cash flows and impact financial condition.

Carbon Capture and Sequestration Project with the Department of Energy (DOE)

During 2010, AEPSC, on behalf of APCo, began the project definition stage for the potential construction of a new commercial scale carbon capture and sequestration (CCS) facility under consideration at the Mountaineer Plant. AEPSC, on behalf of APCo, applied for and was selected to receive funding from the DOE for the project. The DOE will fund 50% of allowable costs incurred for the CCS facility up to a maximum of $334 million. A Front-End Engineering and Design (FEED) study, scheduled for completion during the third quarter of 2011, will refine the total cost estimate for the CCS facility. Results from the FEED study will be evaluated by management before any decision is made to seek the necessary regulatory approvals to build the CCS facility. As of December 31, 2010, APCo has incurred $14 million in total costs and has received $5 million of DOE funding resulting in a net $9 million balance included in Construction Work In Progress on the Consolidated Balance Sheets. If APCo is unable to recover the costs of the CCS project, it would reduce future net income and cash flows.

APCo's Filings for an IGCC Plant

In 2008, the Virginia SCC issued an order denying APCo's request for a surcharge rate mechanism to provide for the timely recovery of pre-construction costs and the ongoing financing costs of the project during the construction period, as well as the capital costs, operating costs and a return on common equity once the facility is placed into commercial operation. The order was based upon the Virginia SCC's finding that the estimated cost of the plant was uncertain and may escalate. The Virginia SCC also expressed concerns that the estimated costs did not include a retrofitting of carbon capture and sequestration facilities. During 2009, based on the order received in Virginia, the WVPSC removed the IGCC case as an active case from its docket and indicated that the conditional CPCN granted in 2008 must be reconsidered if and when APCo proceeds with the IGCC plant.

Through December 31, 2010, APCo deferred for future recovery pre-construction IGCC costs of approximately $9 million applicable to its West Virginia jurisdiction, approximately $2 million applicable to its FERC jurisdiction and approximately $9 million applicable to its Virginia jurisdiction.

APCo will not start construction of the IGCC plant until sufficient assurance of full cost recovery exists in Virginia and West Virginia. If the plant is cancelled, APCo plans to seek recovery of its prudently incurred deferred pre-construction costs which, if not recoverable, would reduce future net income and cash flows and impact financial condition.

APCo's and WPCo's Expanded Net Energy Charge (ENEC) Filing

In September 2009, the WVPSC issued an order approving APCo's and WPCo's March 2009 ENEC request. The approved order provided for recovery of an under-recovered balance plus a projected increase in ENEC costs over a four-year phase-in period with an overall increase of $355 million and a first-year increase of $124 million, effective October 2009. The WVPSC also approved a fixed annual carrying cost rate of 4%, effective October 2009, to be applied to the incremental deferred regulatory asset balance that will result from the phase-in plan and lowered annual coal cost projections by $27 million.

In June 2010, the WVPSC approved a settlement agreement for $96 million, including $10 million of construction surcharges related to APCo's and WPCo's second year ENEC increase. The settlement agreement provided for recovery of the amounts related to the renegotiated coal contracts and allows APCo to accrue weighted average cost of capital carrying charge on the excess under-recovery balance due to the ENEC phase-in as adjusted for the impacts of Accumulated Deferred Income Taxes. As of December 31, 2010, APCo's ENEC under-recovery balance was $361 million, excluding $3 million of unrecognized equity carrying costs, which is included in noncurrent regulatory assets. The new rates became effective in July 2010.

PSO Rate Matters

PSO Fuel and Purchased Power

2006 and Prior Fuel and Purchased Power

The OCC filed a complaint with the FERC related to the allocation of off-system sales margins (OSS) among the AEP operating companies in accordance with a FERC-approved allocation agreement. The FERC issued an adverse ruling in 2008. As a result, PSO recorded a regulatory liability in 2008 to return reallocated OSS to customers. Starting in March 2009, PSO refunded the additional reallocated OSS to its customers through February 2010.

A reallocation of purchased power costs among AEP West companies for periods prior to 2002 resulted in an under-recovery of $42 million of PSO fuel costs. PSO recovered the $42 million by offsetting it against an existing fuel over-recovery during the period June 2007 through May 2008. The Oklahoma Industrial Energy Consumers (OIEC) contended that PSO should not have collected the $42 million without specific OCC approval. In December 2010, the OCC issued orders which approved PSO's 2006 and prior fuel and purchased power costs without any adjustments.

2008 Fuel and Purchased Power

In July 2009, the OCC initiated a proceeding to review PSO's fuel and purchased power adjustment clause for the calendar year 2008 and also initiated a prudence review of the related costs. In March 2010, the Oklahoma Attorney General and the OIEC recommended the fuel clause adjustment rider be amended so that the shareholder's portion of off-system sales margins decrease from 25% to 10%. The OIEC also recommended that the OCC conduct a comprehensive review of all affiliate transactions during 2007 and 2008. In July 2010, additional testimony regarding the 2007 transfer of ERCOT trading contracts to AEPEP was filed. The testimony included unquantified refund recommendations relating to re-pricing of contract transactions. Hearings are currently scheduled for March 2011. If the OCC were to issue an unfavorable decision, it could reduce future net income and cash flows and impact financial condition.

2008 Oklahoma Base Rate Appeal

In January 2009, the OCC issued a final order approving an $81 million increase in PSO's non-fuel base revenues based on a 10.5% return on common equity. The new rates reflecting the final order were implemented with the first billing cycle of February 2009. PSO and intervenors appealed various issues but the Court of Civil Appeals affirmed the OCC's decision. No parties sought rehearing or appeal and, as a result, this case has concluded.

2010 Oklahoma Base Rate Case

In July 2010, PSO filed a request with the OCC to increase annual base rates by $82 million, including $30 million that is currently being recovered through a rider. The requested net annual increase to ratepayers would be $52 million. The requested increase included a $24 million increase in depreciation and an 11.5% return on common equity. In January 2011, the OCC approved a settlement agreement which did not change annual revenue or depreciation rates, but transferred $30 million into base rates that was previously being recovered through a capital investment rider. The order provided a 10.15% return on common equity and new rates were effective in February 2011.

I&M Rate Matters

Indiana Fuel Clause Filing (Cook Plant Unit 1 Fire and Shutdown)

I&M filed applications with the IURC to increase its fuel adjustment charge by approximately $53 million for the period of April 2009 through September 2009. The filings sought increases for previously under-recovered fuel clause expenses.

As fully discussed in the "Cook Plant Unit 1 Fire and Shutdown" section of Note 6, Cook Plant Unit 1 (Unit 1) was shut down in September 2008 due to significant turbine damage and a small fire on the electric generator. Unit 1 was placed back into service in December 2009 at slightly reduced power. The unit outage resulted in increased replacement power fuel costs. The filing only requested the cost of replacement power through mid-December 2008, the date when I&M began receiving accidental outage insurance proceeds. I&M committed to absorb the remaining costs of replacement power through the date the unit returned to service, which occurred in December 2009.

I&M reached an agreement with intervenors, which was approved by the IURC in March 2009, to collect its existing prior period under-recovery regulatory asset deferral balance over twelve months instead of over six months as initially proposed. Under the agreement, the fuel factors were placed into effect, subject to refund, and a subdocket was established to consider issues relating to the Unit 1 shutdown including the treatment of the accidental outage insurance proceeds. I&M maintains a separate accidental outage policy with NEIL. In 2009, I&M recorded $185 million in revenue under the policy and reduced the cost of replacement power in customers' bills by $78 million.

In October 2010, the Indiana/Michigan Industrial Group and the Indiana Office of Utility Consumer Counselor filed testimony which recommended I&M pay to customers a portion of the accidental outage insurance proceeds up to the extent not previously paid to customers through the fuel adjustment clause or needed to cover costs not covered by I&M's property damage insurance policy. In January 2011, a settlement agreement was filed with the IURC. The settlement stated (a) that I&M will credit an additional $14 million to customers through the fuel adjustment clause, (b) that the parties to the settlement will not oppose the need to replace the existing low-pressure turbine at Cook Unit 1, and (c) that the parties to the settlement agree that the cost of the replacement should not be offset by the accidental outage insurance proceeds received by I&M. In February 2011, the IURC approved the settlement agreement as filed.

Michigan 2009 Power Supply Cost Recovery (PSCR) Reconciliation (Cook Plant Unit 1 Fire and Shutdown)

In March 2010, I&M filed its 2009 PSCR reconciliation with the MPSC. The filing included an adjustment to exclude from the PSCR the incremental fuel cost of replacement power due to the Unit 1 outage from mid-December 2008 through December 2009, the period during which I&M received and recognized the accidental outage insurance proceeds. Management believes that I&M is entitled to retain the accidental outage insurance proceeds since it made customers whole regarding the replacement power costs. In October 2010, a settlement agreement was filed with the MPSC which included deferring the Unit 1 outage issue to the 2010 PSCR reconciliation, which will be filed in March 2011. If any fuel clause revenues or accidental outage insurance proceeds have to be paid to customers, it would reduce future net income and cash flows and impact financial condition. See the "Cook Plant Unit 1 Fire and Shutdown" section of Note 6.

Michigan Base Rate Filing

In January 2010, I&M filed with the MPSC a request for a $63 million increase in annual base rates based on an 11.75% return on common equity. Starting with the August 2010 billing cycle, I&M, with MPSC authorization, implemented a $44 million interim rate increase. The interim increase excluded new trackers and regulatory assets for which I&M was not currently incurring expenses. In October 2010, a settlement agreement was approved by the MPSC to increase annual base rates by $36 million based on a 10.35% return on common equity, effective December 2010, plus separate recovery of approximately $7 million of customer choice implementation costs over a two year period beginning April 2011. In addition, the approved revenue requirement includes the amortization of $6 million in previously expensed restructuring costs over five years, which I&M deferred in October 2010 and began amortizing in December 2010. Also, the approved settlement agreement provided for sharing of off-system sales margins between customers (75%) and I&M (25%) with customers receiving a credit in future Power Supply Cost Recovery proceedings for their jurisdictional share of any off-system sales margins. Through December 2010, I&M recorded a provision for refund of $3 million, including interest, related to interim rates that were in effect through November 2010. In January 2011, I&M filed an application with the MPSC requesting the MPSC find that $3 million, including interest, is the total amount to be refunded to customers. I&M is proposing to refund this amount to customers during April 2011. A decision from the MPSC is pending.

Kentucky Rate Matters

Kentucky Base Rate Filing

In December 2009, KPCo filed a base rate case with the KPSC to increase base revenues by $124 million annually based on an 11.75% return on common equity. The base rate case also requested recovery of deferred storm restoration expenses over a three-year period. In June 2010, the KPSC approved a settlement agreement to increase base revenues by $64 million annually based on a 10.5% return on common equity. The settlement agreement included recovery of $23 million of deferred storm restoration expenses over five years. New rates became effective with the first billing cycle of July 2010.

FERC Rate Matters

Seams Elimination Cost Allocation (SECA) Revenue Subject to Refund

In 2004, AEP eliminated transaction-based through-and-out transmission service (T&O) charges in accordance with FERC orders and collected, at the FERC's direction, load-based charges, referred to as RTO SECA, to partially mitigate the loss of T&O revenues on a temporary basis through March 2006. Intervenors objected to the temporary SECA rates. The FERC set SECA rate issues for hearing and ordered that the SECA rate revenues be collected, subject to refund. The AEP East companies recognized gross SECA revenues of $220 million from 2004 through 2006 when the SECA rates terminated.

In 2006, a FERC Administrative Law Judge (ALJ) issued an initial decision finding that the SECA rates charged were unfair, unjust and discriminatory and that new compliance filings and refunds should be made. The ALJ also found that any unpaid SECA rates must be paid in the recommended reduced amount.

AEP filed briefs jointly with other affected companies asking the FERC to reverse the decision. In May 2010, the FERC issued an order that generally supports AEP's position and required a compliance filing to be filed with the FERC by August 2010. In June 2010, AEP and other affected companies filed a joint request for rehearing with the FERC.

In August 2010, the affected companies, including the AEP East companies, filed a compliance filing with the FERC. If the compliance filing is accepted, the AEP East companies would have to pay refunds of approximately $20 million including estimated interest of $5 million. The AEP East companies could also potentially receive payments up to approximately $10 million including estimated interest of $3 million. A decision is pending from the FERC.

The FERC has approved settlements applicable to $112 million of SECA revenue. The AEP East companies provided reserves for net refunds for SECA settlements applicable to the remaining $108 million of SECA revenues collected. Based on the AEP East companies' analysis of the May 2010 order and the compliance filing, management believes that the reserve is adequate to pay the refunds, including interest, that will be required should the May 2010 order or the compliance filing be made final. Management cannot predict the ultimate outcome of this proceeding at the FERC which could impact future net income and cash flows.

Modification of the Transmission Agreement (TA)

The AEP East companies are parties to the TA that provides for a sharing of the cost of transmission lines operated at 138-kV and above and transmission stations containing extra-high voltage facilities. In June 2009, AEPSC, on behalf of the parties to the TA, filed with the FERC a request to modify the TA. Under the proposed amendments, KGPCo and WPCo will be added as parties to the TA. In addition, the amendments would provide for the allocation of PJM transmission costs generally on the basis of the TA parties' 12-month coincident peak and reimburse transmission revenues based on individual cost of service instead of the MLR method used in the present TA. In October 2010, the FERC approved a settlement agreement for the new TA effective November 1, 2010. The impacts of the settlement agreement will be phased-in for retail rate making purposes in certain jurisdictions over periods of up to four years.

PJM/MISO Market Flow Calculation Settlement Adjustments

During 2009, an analysis conducted by MISO and PJM discovered several instances of unaccounted for power flows on numerous coordinated flowgates. These flows affected the settlement data for congestion revenues and expenses and dated back to the start of the MISO market in 2005. In January 2011, PJM and MISO reached a settlement agreement where the parties agreed to net various issues to zero. This settlement was filed with the FERC in January 2011. PJM and MISO are currently awaiting final approval from the FERC.

5. EFFECTS OF REGULATION

Regulatory assets are comprised of the following items:

	December 31, 2010		December 31, 2009	Remaining Recovery Period
Current Regulatory Assets	(in millions)			
Under-recovered Fuel Costs - earns a return	$ 73		$ 85	1 year
Under-recovered Fuel Costs - does not earn a return	8		-	1 year
Total Current Regulatory Assets	$ 81		$ 85	
Noncurrent Regulatory Assets				
Regulatory assets not yet being recovered pending future proceedings to determine the recovery method and timing:				
Regulatory Assets Currently Earning a Return				
Customer Choice Deferrals - CSPCo, OPCo	$ 59		$ 57	
Storm Related Costs - CSPCo, OPCo, TCC	55		49	
Line Extension Carrying Costs - CSPCo, OPCo	55		43	
Acquisition of Monongahela Power - CSPCo	8		10	
Other Regulatory Assets Not Yet Being Recovered	7		1	
Regulatory Assets Currently Not Earning a Return				
Mountaineer Carbon Capture and Storage Product Validation Facility - APCo	60		111	
Environmental Rate Adjustment Clause - APCo	56		25	
Storm Related Costs - APCo, KGPCo, PSO, SWEPCo	45		-	
Deferred Wind Power Costs - APCo	29		5	
Special Rate Mechanism for Century Aluminum - APCo	13		12	
Acquisition of Monongahela Power - CSPCo	4		-	
Transmission Rate Adjustment Clause - APCo	-	(a)	26	
Storm Related Costs - KPCo	-	(b)	24	
Other Regulatory Assets Not Yet Being Recovered	4		18	
Total Regulatory Assets Not Yet Being Recovered	395		381	
Regulatory assets being recovered:				
Regulatory Assets Currently Earning a Return				
Fuel Adjustment Clause - OPCo	476		341	2 to 8 years
Expanded Net Energy Charge - APCo	361	(c)	-	3 years
Unamortized Loss on Reacquired Debt	93		99	33 years
Storm Related Costs - PSO	38		53	3 years
RTO Formation/Integration Costs	21		23	9 years
Red Rock Generating Facility - PSO	10		11	46 years
Economic Development Rider - CSPCo, OPCo	1		12	1 year
Other Regulatory Assets Being Recovered	21		23	various
Regulatory Assets Currently Not Earning a Return				
Pension and OPEB Funded Status	2,161		2,139	13 years
Income Taxes, Net	1,097		966	37 years
Cook Nuclear Plant Refueling Outage Levelization - I&M	54		22	3 years
Postemployment Benefits	51		52	4 years
Storm Related Costs - KPCo	21	(b)	-	5 years
Transmission Rate Adjustment Clause - APCo	19	(a)	-	2 years
Asset Retirement Obligation - APCo, I&M	15		16	10 years
Restructuring Transition Costs - TCC	14		25	5 years
Off-system Sales Margin Sharing - I&M	13		18	1 year
Vegetation Management - PSO	13		16	1 year
Virginia Environmental and Reliability Costs Recovery - APCo	4		76	3 years
Expanded Net Energy Charge - APCo	-	(c)	282	
Other Regulatory Assets Being Recovered	65		40	various
Total Regulatory Assets Being Recovered	4,548		4,214	
Total Noncurrent Regulatory Assets	$ 4,943		$ 4,595	

(a) Recovery of regulatory asset through the transmission rate adjustment clause.
(b) Recovery of regulatory asset was granted during 2010.
(c) The majority of the balance results from the ENEC phase-in plan and earns a weighted average cost of capital carrying charge.

Regulatory liabilities are comprised of the following items:

	December 31, 2010	December 31, 2009	Remaining Refund Period
Current Regulatory Liability	(in millions)		
Over-recovered Fuel Costs - pays a return	$ 16	$ 65	1 year
Over-recovered Fuel Costs - does not pay a return	1	11	1 year
Total Current Regulatory Liability	$ 17	$ 76	
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities not yet being paid:			
Regulatory Liabilities Currently Paying a Return			
Refundable Construction Financing Costs - SWEPCo	$ 20	$ -	
Other Regulatory Liabilities Not Yet Being Paid	-	3	
Regulatory Liabilities Currently Not Paying a Return			
Over-Recovery of gridSMART® Costs - CSPCo, PSO	10	9	
Other Regulatory Liabilities Not Yet Being Paid	11	10	
Total Regulatory Liabilities Not Yet Being Paid	41	22	
Regulatory liabilities being paid:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	2,222	2,048	(a)
Advanced Metering Infrastructure Surcharge - TCC, TNC	61	30	10 years
Deferred Investment Tax Credits	32	41	up to 12 years
Excess Earnings - SWEPCo, TNC	13	11	43 years
Transmission Cost Recovery Rider - CSPCo, OPCo	2	25	1 year
Other Regulatory Liabilities Being Paid	2	2	various
Regulatory Liabilities Currently Not Paying a Return			
Excess Asset Retirement Obligations for Nuclear Decommissioning Liability - I&M	354	281	(b)
Deferred Investment Tax Credits	242	239	up to 76 years
Unrealized Gain on Forward Commitments	60	74	5 years
Spent Nuclear Fuel Liability - I&M	42	41	(b)
Over-recovery of Transition Charges - TCC	38	38	9 years
Deferred State Income Tax Coal Credits - APCo	29	28	9 years
Over-recovery of PJM Expenses - I&M	12	18	1 year
Energy Efficiency/Peak Demand Reduction	10	2	2 years
Other Regulatory Liabilities Being Paid	11	9	various
Total Regulatory Liabilities Being Paid	3,130	2,887	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 3,171	$ 2,909	

(a) Relieved as removal costs are incurred.
(b) Relieved when plant is decommissioned.

6. COMMITMENTS, GUARANTEES AND CONTINGENCIES

We are subject to certain claims and legal actions arising in our ordinary course of business. In addition, our business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation against us cannot be predicted. For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material adverse effect on our financial statements.

COMMITMENTS

Construction and Commitments

The AEP System has substantial construction commitments to support its operations and environmental investments. In managing the overall construction program and in the normal course of business, we contractually commit to third-party construction vendors for certain material purchases and other construction services. We forecast approximately $2.5 billion and $2.6 billion of construction expenditures excluding AFUDC and capitalized interest for 2011 and 2012, respectively. The subsidiaries purchase fuel, materials, supplies, services and property, plant and equipment under contract as part of their normal course of business. Certain supply contracts contain penalty provisions for early termination.

The following table summarizes our actual contractual commitments at December 31, 2010:

Contractual Commitments	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 2,810	$ 3,974	$ 2,543	$ 3,718	$ 13,045
Energy and Capacity Purchase Contracts (b)	69	199	204	1,101	1,573
Total	$ 2,879	$ 4,173	$ 2,747	$ 4,819	$ 14,618

(a) Represents contractual commitments to purchase coal, natural gas, uranium and other consumables as fuel for electric generation along with related transportation of the fuel.
(b) Represents contractual commitments for energy and capacity purchase contracts.

GUARANTEES

We record liabilities for guarantees in accordance with the accounting guidance for "Guarantees." There is no collateral held in relation to any guarantees in excess of our ownership percentages. In the event any guarantee is drawn, there is no recourse to third parties unless specified below.

Letters of Credit

We enter into standby letters of credit with third parties. As Parent, we issue all of these letters of credit in our ordinary course of business on behalf of our subsidiaries. These letters of credit cover items such as gas and electricity risk management contracts, construction contracts, insurance programs, security deposits and debt service reserves.

We have two $1.5 billion credit facilities, of which $750 million may be issued under one credit facility as letters of credit. In June 2010, we terminated one of the $1.5 billion facilities that was scheduled to mature in March 2011 and replaced it with a new $1.5 billion credit facility which matures in 2013 and allows for the issuance of up to $600 million as letters of credit. As of December 31, 2010, the maximum future payments for letters of credit issued under the two $1.5 billion credit facilities were $124 million with maturities ranging from January 2011 to November 2011.

In June 2010, we reduced a $627 million credit agreement to $478 million. As of December 31, 2010, $477 million of letters of credit with maturities ranging from March 2011 to April 2011 were issued by subsidiaries under this credit agreement to support variable rate Pollution Control Bonds.

Guarantees of Third-Party Obligations

SWEPCo

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provides guarantees of mine reclamation of approximately $65 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by Sabine Mining Company (Sabine), a consolidated variable interest entity. This guarantee ends upon depletion of reserves and completion of final reclamation. Based on the latest study, we estimate the reserves will be depleted in 2036 with final reclamation completed by 2046 at an estimated cost of approximately $58 million. As of December 31, 2010, SWEPCo has collected approximately $49 million through a rider for final mine closure and reclamation costs, of which $2 million is recorded in Other Current Liabilities, $25 million is recorded in Deferred Credits and Other Noncurrent Liabilities and $22 million is recorded in Asset Retirement Obligations on our Consolidated Balance Sheets.

Sabine charges SWEPCo, its only customer, all of its costs. SWEPCo passes these costs to customers through its fuel clause.

Indemnifications and Other Guarantees

Contracts

We enter into several types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, our exposure generally does not exceed the sale price. The status of certain sale agreements is discussed in the "Dispositions" section of Note 7. These sale agreements include indemnifications with a maximum exposure related to the collective purchase price. This maximum exposure of approximately $1 billion relates to the Bank of America (BOA) litigation indemnity pertaining to the sale of Houston Pipeline Company in 2005 (see "Enron Bankruptcy" section of this note), of which $448 million is recorded in Current Liabilities – Deferred Gain and Accrued Litigation Costs on the Consolidated Balance Sheet as of December 31, 2010. In February 2011, all matters related to the BOA litigation were resolved and we paid BOA $425 million. There are no material amounts recorded for any indemnifications other than the deferred gain (plus interest and attorneys' fees) related to the BOA litigation which settled in February 2011.

Lease Obligations

We lease certain equipment under master lease agreements. See "Master Lease Agreements" and "Railcar Lease" sections of Note 13 for disclosure of lease residual value guarantees.

ENVIRONMENTAL CONTINGENCIES

Federal EPA Complaint and Notice of Violation

The Federal EPA, certain special interest groups and a number of states alleged that APCo, CSPCo, I&M and OPCo modified certain units at their coal-fired generating plants in violation of the NSR requirements of the CAA. Cases with similar allegations against CSPCo, Dayton Power and Light Company and Duke Energy Ohio, Inc. were also filed related to their jointly-owned units. The cases were settled with the exception of a case involving a jointly-owned Beckjord unit which had a liability trial. Following two liability trials, the jury found no liability at the jointly-owned Beckjord unit. The defendants and the plaintiffs appealed to the Seventh Circuit Court of Appeals. In October 2010, the Seventh Circuit dismissed all remaining claims in these cases. Beckjord is operated by Duke Energy Ohio, Inc.

SWEPCo Citizen Suit and Notice of Violation

In 2005, two special interest groups, Sierra Club and Public Citizen, filed a complaint alleging violations of the CAA at SWEPCo's Welsh Plant. In 2008, a consent decree resolved all claims in the case and in the pending appeal of an altered permit for the Welsh Plant. The consent decree required SWEPCo to install continuous particulate emission monitors at the Welsh Plant, secure 65 MW of renewable energy capacity, fund $2 million in emission reduction, energy efficiency or environmental mitigation projects and pay a portion of plaintiffs' attorneys' fees and costs.

The Federal EPA issued a Notice of Violation (NOV) based on alleged violations of a percent sulfur in fuel limitation and the heat input values listed in a previous state permit similar to the claims made in the citizen suit. The NOV also alleges that a permit alteration issued by the Texas Commission on Environmental Quality in 2007 was improper. In March 2008, SWEPCo met with the Federal EPA to discuss the alleged violations. The Federal EPA did not object to the settlement of the citizen suit and has taken no further action. We are unable to predict the timing of any future action by the Federal EPA. We are unable to determine a range of potential losses that are reasonably possible of occurring.

Carbon Dioxide Public Nuisance Claims

In 2004, eight states and the City of New York filed an action in Federal District Court for the Southern District of New York against AEP, AEPSC, Cinergy Corp, Xcel Energy, Southern Company and Tennessee Valley Authority. The Natural Resources Defense Council, on behalf of three special interest groups, filed a similar complaint against the same defendants. The actions allege that CO_2 emissions from the defendants' power plants constitute a public nuisance under federal common law due to impacts of global warming and sought injunctive relief in the form of specific emission reduction commitments from the defendants. The trial court dismissed the lawsuits.

In September 2009, the Second Circuit Court of Appeals issued a ruling on appeal remanding the cases to the Federal District Court for the Southern District of New York. The Second Circuit held that the issues of climate change and global warming do not raise political questions and that Congress' refusal to regulate CO_2 emissions does not mean that plaintiffs must wait for an initial policy determination by Congress or the President's administration to secure the relief sought in their complaints. The court stated that Congress could enact comprehensive legislation to regulate CO_2 emissions or that the Federal EPA could regulate CO_2 emissions under existing CAA authorities and that either of these actions could override any decision made by the district court under federal common law. The Second Circuit did not rule on whether the plaintiffs could proceed with their state common law nuisance claims. In December 2010, the defendants' petition for review by the U.S. Supreme Court was granted. Briefing is underway and the case will be heard in April 2011. We believe the actions are without merit and intend to continue to defend against the claims.

In October 2009, the Fifth Circuit Court of Appeals reversed a decision by the Federal District Court for the District of Mississippi dismissing state common law nuisance claims in a putative class action by Mississippi residents asserting that CO_2 emissions exacerbated the effects of Hurricane Katrina. The Fifth Circuit held that there was no exclusive commitment of the common law issues raised in plaintiffs' complaint to a coordinate branch of government and that no initial policy determination was required to adjudicate these claims. The court granted petitions for rehearing. An additional recusal left the Fifth Circuit without a quorum to reconsider the decision and the appeal was dismissed, leaving the district court's decision in place. Plaintiffs filed a petition with the U.S. Supreme Court asking the court to remand the case to the Fifth Circuit and reinstate the panel decision. The petition was denied in January 2011.

We are unable to determine a range of potential losses that are reasonably possible of occurring.

Alaskan Villages' Claims

In 2008, the Native Village of Kivalina and the City of Kivalina, Alaska filed a lawsuit in Federal Court in the Northern District of California against AEP, AEPSC and 22 other unrelated defendants including oil and gas companies, a coal company and other electric generating companies. The complaint alleges that the defendants' emissions of CO_2 contribute to global warming and constitute a public and private nuisance and that the defendants are acting together. The complaint further alleges that some of the defendants, including AEP, conspired to create a false scientific debate about global warming in order to deceive the public and perpetuate the alleged nuisance. The plaintiffs also allege that the effects of global warming will require the relocation of the village at an alleged cost of $95 million to $400 million. In October 2009, the judge dismissed plaintiffs' federal common law claim for nuisance, finding the claim barred by the political question doctrine and by plaintiffs' lack of standing to bring the claim. The judge also dismissed plaintiffs' state law claims without prejudice to refiling in state court. The plaintiffs appealed the decision. Briefing is complete and no date has been set for oral argument. The defendants requested that the court defer setting this case for oral argument until after the Supreme Court issues its decision in the CO_2 public nuisance case discussed above. We believe the action is without merit and intend to defend against the claims. We are unable to determine a range of potential losses that are reasonably possible of occurring.

The Comprehensive Environmental Response Compensation and Liability Act (Superfund) and State Remediation

By-products from the generation of electricity include materials such as ash, slag, sludge, low-level radioactive waste and SNF. Coal combustion by-products, which constitute the overwhelming percentage of these materials, are typically treated and deposited in captive disposal facilities or are beneficially utilized. In addition, our generating plants and transmission and distribution facilities have used asbestos, polychlorinated biphenyls and other hazardous and nonhazardous materials. We currently incur costs to dispose of these substances safely.

Superfund addresses clean-up of hazardous substances that have been released to the environment. The Federal EPA administers the clean-up programs. Several states have enacted similar laws. At December 31, 2010, our subsidiaries are named by the Federal EPA as a Potentially Responsible Party (PRP) for four sites for which alleged liability is unresolved. There are eight additional sites for which our subsidiaries have received information requests which could lead to PRP designation. Our subsidiaries have also been named potentially liable at four sites under state law including the I&M site discussed in the next paragraph. In those instances where we have been named a PRP or defendant, our disposal or recycling activities were in accordance with the then-applicable laws and regulations. Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories. Liability has been resolved for a number of sites with no significant effect on net income.

In 2008, I&M received a letter from the Michigan Department of Environmental Quality (MDEQ) concerning conditions at a site under state law and requesting I&M take voluntary action necessary to prevent and/or mitigate public harm. I&M started remediation work in accordance with a plan approved by MDEQ and recorded a provision of approximately $11 million. As the remediation work is completed, I&M's cost may continue to increase as new information becomes available concerning either the level of contamination at the site or changes in the scope of remediation required by the MDEQ. We cannot predict the amount of additional cost, if any.

We evaluate the potential liability for each Superfund site separately, but several general statements can be made about our potential future liability. Allegations that materials were disposed at a particular site are often unsubstantiated and the quantity of materials deposited at a site can be small and often nonhazardous. Although Superfund liability has been interpreted by the courts as joint and several, typically many parties are named as PRPs for each site and several of the parties are financially sound enterprises. At present, our estimates do not anticipate material cleanup costs for any of our identified Superfund sites, except the I&M site discussed above.

Amos Plant – State and Federal Enforcement Proceedings

In March 2010, we received a letter from the West Virginia Department of Environmental Protection, Division of Air Quality (DAQ), alleging that at various times in 2007 through 2009 the units at Amos Plant reported periods of excess opacity (indicator of compliance with particulate matter emission limits) that lasted for more than thirty consecutive minutes in a 24-hour period and that certain required notifications were not made. We met with representatives of DAQ to discuss these occurrences and the steps we have taken to prevent a recurrence. DAQ indicated that additional enforcement action may be taken, including imposition of a civil penalty of approximately $240 thousand. We have denied that violations of the reporting requirements occurred and maintain that the proper reporting was done. We continue to discuss the resolution of these issues with DAQ, but cannot predict the outcome of these discussions or the amount of any penalty that may be assessed.

In March 2010, we received a request to show cause from the Federal EPA alleging that certain reporting requirements under Superfund and the Emergency Planning and Community Right-to-Know Act had been violated and inviting us to engage in settlement negotiations. The request includes a proposed civil penalty of approximately $300 thousand. We indicated our willingness to engage in good faith negotiations and provided additional information to representatives of the Federal EPA. We have not admitted that any violations occurred or that the amount of the proposed penalty is reasonable.

Defective Environmental Equipment

As part of our continuing environmental investment program, we chose to retrofit wet flue gas desulfurization systems on several units utilizing the jet bubbling reactor (JBR) technology. The retrofits on two Cardinal Plant units and a Conesville Plant unit are operational. Due to unexpected operating results, we completed an extensive review in 2009 of the design and manufacture of the JBR internal components. Our review concluded that there were fundamental design deficiencies and that inferior and/or inappropriate materials were selected for the internal fiberglass components. We initiated discussions with Black & Veatch, the original equipment manufacturer, to develop a repair or replacement corrective action plan. In 2010, we settled with Black & Veatch and resolved the issues involving the internal components and JBR vessel corrosion. These settlements resulted in an immaterial increase in the capitalized costs of the projects for modification of the scope of the contracts.

NUCLEAR CONTINGENCIES

I&M owns and operates the two-unit 2,191 MW Cook Plant under licenses granted by the Nuclear Regulatory Commission (NRC). We have a significant future financial commitment to dispose of SNF and to safely decommission and decontaminate the plant. The licenses to operate the two nuclear units at the Cook Plant expire in 2034 and 2037. The operation of a nuclear facility also involves special risks, potential liabilities and specific regulatory and safety requirements. 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 at any nuclear plant in the U.S. Should a nuclear incident occur at any nuclear power plant in the U.S., the liability could be substantial.

Decommissioning and Low Level Waste Accumulation Disposal

The cost to decommission a nuclear plant is affected by NRC regulations and the SNF disposal program. Decommissioning costs are accrued over the service life of the Cook Plant. The most recent decommissioning cost study was performed in 2009. According to that study, the estimated cost of decommissioning and disposal of low-level radioactive waste ranges from $831 million to $1.5 billion in 2009 nondiscounted dollars. The wide range in estimated costs is caused by variables in assumptions. I&M recovers estimated decommissioning costs for the Cook Plant in its rates. The amount recovered in rates was $14 million in 2010, $16 million in 2009 and $27 million in 2008. Reduced annual decommissioning cost recovery amounts reflect the units' longer estimated life and operating licenses granted by the NRC. Decommissioning costs recovered from customers are deposited in external trusts.

At December 31, 2010 and 2009, the total decommissioning trust fund balance was $1.2 billion and $1.1 billion, respectively. Trust fund earnings increase the fund assets and decrease the amount remaining to be recovered from ratepayers. The decommissioning costs (including interest, unrealized gains and losses and expenses of the trust funds) increase or decrease the recorded liability.

I&M continues to work with regulators and customers to recover the remaining estimated costs of decommissioning the Cook Plant. However, future net income, cash flows and possibly financial condition would be adversely affected if the cost of SNF disposal and decommissioning continues to increase and cannot be recovered.

SNF Disposal

The Federal government is responsible for permanent SNF disposal and assesses fees to nuclear plant owners for SNF disposal. A fee of one mill per KWH for fuel consumed after April 6, 1983 at the Cook Plant is being collected from customers and remitted to the U.S. Treasury. At December 31, 2010 and 2009, fees and related interest of $265 million and $265 million, respectively, for fuel consumed prior to April 7, 1983 have been recorded as Long-term Debt and funds collected from customers along with related earnings totaling $307 million and $306 million, respectively, to pay the fee are recorded as part of Spent Nuclear Fuel and Decommissioning Trusts. I&M has not paid the government the pre-April 1983 fees due to continued delays and uncertainties related to the federal disposal program.

See "Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal" section of Note 11 for disclosure of the fair value of assets within the trusts.

Nuclear Incident Liability

I&M carries insurance coverage for property damage, decommissioning and decontamination at the Cook Plant in the amount of $1.8 billion. I&M purchases $1 billion of excess coverage for property damage, decommissioning and decontamination. Additional insurance provides coverage for a weekly indemnity payment resulting from an insured accidental outage. I&M utilizes an industry mutual insurer for the placement of this insurance coverage. Participation in this mutual insurance requires a contingent financial obligation of up to $41 million for I&M which is assessable if the insurer's financial resources would be inadequate to pay for losses.

The Price-Anderson Act, extended through December 31, 2025, establishes insurance protection for public liability arising from a nuclear incident at $12.6 billion and covers any incident at a licensed reactor in the U.S. Commercially available insurance, which must be carried for each licensed reactor, provides $375 million of coverage. In the event of a nuclear incident at any nuclear plant in the U.S., the remainder of the liability would be provided by a deferred premium assessment of $117.5 million on each licensed reactor in the U.S. payable in annual installments of $17.5 million. As a result, I&M could be assessed $235 million per nuclear incident payable in annual installments of $35 million. The number of incidents for which payments could be required is not limited.

In the event of an incident of a catastrophic nature, I&M is initially covered for the first $375 million through commercially available insurance. The next level of liability coverage of up to $12.2 billion would be covered by claims made under the Price-Anderson Act. If the liability were in excess of amounts recoverable from insurance and retrospective claim payments made under the Price-Anderson Act, I&M would seek to recover those amounts from customers through rate increases. In the event nuclear losses or liabilities are underinsured or exceed accumulated funds and recovery from customers is not possible, net income, cash flows and financial condition could be adversely affected.

Cook Plant Unit 1 Fire and Shutdown

In September 2008, I&M shut down Cook Plant Unit 1 (Unit 1) due to turbine vibrations, caused by blade failure, which resulted in significant turbine damage and a small fire on the electric generator. This equipment, located in the turbine building, is separate and isolated from the nuclear reactor. The turbine rotors that caused the vibration were installed in 2006 and are within the vendor's warranty period. The warranty provides for the repair or replacement of the turbine rotors if the damage was caused by a defect in materials or workmanship. Repair of the property damage and replacement of the turbine rotors and other equipment could cost up to approximately $395 million. Management believes that I&M should recover a significant portion of these costs through the turbine vendor's warranty, insurance and the regulatory process. I&M repaired Unit 1 and it resumed operations in December 2009 at slightly reduced power. The Unit 1 rotors were repaired and reinstalled due to the extensive lead time required to manufacture and install new turbine rotors. As a result, the replacement of the repaired turbine rotors and other equipment is scheduled for the Unit 1 planned outage in the fall of 2011.

I&M maintains property insurance through NEIL with a $1 million deductible. As of December 31, 2010, we recorded $46 million in Prepayments and Other Current Assets on our Consolidated Balance Sheets representing estimated recoverable amounts under the property insurance policy. Through December 31, 2010, I&M received partial payments of $203 million from NEIL for the cost incurred to date to repair the property damage.

I&M also maintains a separate accidental outage policy with NEIL. In 2009, I&M recorded $185 million in revenue under the policy and reduced the cost of replacement power in customers' bills by $78 million.

NEIL is reviewing claims made under the insurance policies to ensure that claims associated with the outage are covered by the policies. The review by NEIL includes the timing of the unit's return to service and whether the return should have occurred earlier reducing the amount received under the accidental outage policy. The treatment of the remaining accidental outage policy revenues through fuel clauses is discussed in "I&M Rate Matters" section of Note 4. The treatment of property damage costs, replacement power costs and insurance proceeds will be the subject of future regulatory proceedings in Indiana and Michigan. If the ultimate costs of the incident are not covered by warranty, insurance or through the regulatory process or if any future regulatory proceedings are adverse, it could have an adverse impact on net income, cash flows and financial condition.

OPERATIONAL CONTINGENCIES

Insurance and Potential Losses

We maintain insurance coverage normal and customary for an integrated electric utility, subject to various deductibles. Our insurance includes coverage for all risks of physical loss or damage to our nonnuclear assets, subject to insurance policy conditions and exclusions. Covered property generally includes power plants, substations, facilities and inventories. Excluded property generally includes transmission and distribution lines, poles and towers. Our insurance programs also generally provide coverage against loss arising from certain claims made by third parties and are in excess of retentions absorbed by us. Coverage is generally provided by a combination of our protected cell of EIS and/or various industry mutual and/or commercial insurance carriers.

See "Nuclear Contingencies" section of this footnote for a discussion of nuclear exposures and related insurance.

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including, but not limited to, liabilities relating to damage to the Cook Plant and costs of replacement power in the event of an incident at the Cook Plant. Future losses or liabilities, if they occur, which are not completely insured, unless recovered from customers, could have a material adverse effect on our net income, cash flows and financial condition.

Fort Wayne Lease

Since 1975, I&M has leased certain energy delivery assets from the City of Fort Wayne, Indiana under a long-term lease that expired on February 28, 2010. I&M negotiated with Fort Wayne to purchase the assets at the end of the lease, but no agreement was reached prior to the end of the lease.

I&M and Fort Wayne reached a settlement agreement. The agreement, signed in October 2010, is subject to approval by the IURC. I&M filed a petition with the IURC seeking approval. If the agreement is approved, I&M will purchase the remaining leased property and settle claims Fort Wayne asserted. The agreement provides that I&M will pay Fort Wayne a total of $39 million, inclusive of interest, over 15 years and Fort Wayne will recognize that I&M is the exclusive electricity supplier in the Fort Wayne area. I&M will seek recovery in rates of the payments made to Fort Wayne. If the agreement is not approved by the IURC, the parties have the right to terminate the agreement and pursue other relief.

Enron Bankruptcy

In 2001, we purchased Houston Pipeline Company (HPL) from Enron. Various HPL-related contingencies and indemnities from Enron remained unsettled at the date of Enron's bankruptcy. In connection with our acquisition of HPL, we entered into an agreement with BAM Lease Company, which granted HPL the exclusive right to use approximately 55 billion cubic feet (BCF) of cushion gas required for the normal operation of the Bammel gas storage facility. At the time of our acquisition of HPL, BOA and certain other banks (the BOA Syndicate) and Enron entered into an agreement granting HPL the exclusive use of the cushion gas. Also at the time of our acquisition, Enron and the BOA Syndicate released HPL from all prior and future liabilities and obligations in connection with the financing arrangement. After the Enron bankruptcy, the BOA Syndicate informed HPL of a purported default by Enron under the terms of the financing arrangement. This dispute was being litigated in federal courts in Texas and New York.

In 2007, the judge in the New York action issued a decision on all claims, including those that were pending trial in Texas, granting BOA summary judgment and dismissing our claims. In August 2008, the New York court entered a final judgment of $346 million. In May 2009, the judge awarded $20 million of attorneys' fees to BOA. In October 2010, the Court of Appeals affirmed the New York district court's decision as to the final judgment of $346 million plus interest and reversed the New York district court decision as to the judgment dismissing our claims against BOA in the Southern District of Texas.

In 2005, we sold our interest in HPL and 30 BCF of working gas for approximately $1 billion. Although the assets were legally transferred, we were unable to determine all costs associated with the transfer until the BOA litigation was resolved. We indemnified the buyer of HPL against any damages up to the purchase price resulting from the BOA litigation, including the right to use the 55 BCF of natural gas through 2031. As a result, we deferred the entire gain related to the sale of HPL (approximately $380 million) pending resolution of the Enron and BOA disputes.

The deferred gain related to the sale of HPL, plus accrued interest and attorneys' fees related to the New York court's judgment was $448 million at December 31, 2010 and is included in Current Liabilities – Deferred Gain and Accrued Litigation Costs on the Consolidated Balance Sheet. $441 million related to this matter was included in Deferred Credits and Other Noncurrent Liabilities on our Consolidated Balance Sheet at December 31, 2009. The effect of this decision had no impact on consolidated net income for 2010.

In February 2011, we reached a settlement with BOA covering claims in both the New York and Texas proceedings and paid BOA $425 million. The settlement covers all claims with BOA and Enron. We received title to the 55 BCF of natural gas in the Bammel storage facility as part of the settlement. We do not expect the effect of the settlement to have a material impact on our 2011 consolidated net income.

Natural Gas Markets Lawsuits

In 2002, the Lieutenant Governor of California filed a lawsuit in Los Angeles County California Superior Court against numerous energy companies, including AEP, alleging violations of California law through alleged fraudulent reporting of false natural gas price and volume information with an intent to affect the market price of natural gas and electricity. AEP was dismissed from the case. A number of similar cases were also filed in California and in state and federal courts in several states making essentially the same allegations under federal or state laws against the same companies. AEP (or a subsidiary) is among the companies named as defendants in some of these cases. These cases are at various pre-trial stages. In 2008, we settled all of the cases pending against us in California. The settlements did not impact 2008 earnings due to provisions made in prior periods. We will continue to defend each remaining case where an AEP company is a defendant. We believe the remaining exposure is immaterial.

7. ACQUISITIONS, DISPOSITIONS AND DISCONTINUED OPERATIONS

ACQUISITIONS

2010

Valley Electric Membership Corporation (Utility Operations segment)

In November 2009, SWEPCo signed a letter of intent to purchase certain transmission and distribution assets of Valley Electric Membership Corporation (VEMCO). In October 2010, SWEPCo finalized the purchase for approximately $102 million and began serving VEMCO's 30,000 customers in Louisiana.

2009

Oxbow Lignite Company and Red River Mining Company (Utility Operations segment)

On December 29, 2009, SWEPCo purchased 50% of the Oxbow Lignite Company, LLC (OLC) membership interest for $13 million. CLECO acquired the remaining 50% membership interest in the OLC for $13 million. The Oxbow Mine is located near Coushatta, Louisiana and will be used as one of the fuel sources for SWEPCo's and CLECO's jointly-owned Dolet Hills Generating Station. SWEPCo will account for OLC as an equity investment. Also, on December 29, 2009, DHLC purchased mining equipment and assets for $16 million from the Red River Mining Company.

2008

Erlbacher companies (AEP River Operations segment)

In June 2008, AEP River Operations purchased certain barging assets from Missouri Barge Line Company, Missouri Dry Dock and Repair Company and Cape Girardeau Fleeting, Inc. (collectively known as Erlbacher companies) for $35 million. These assets were incorporated into AEP River Operations' business which will diversify its customer base.

DISPOSITIONS

2010

Electric Transmission Texas LLC (ETT) (Utility Operations segment)

TCC and TNC sold, at cost, $66 million and $73 million, respectively, of transmission facilities to ETT for the year ended December 31, 2010.

Intercontinental Exchange, Inc. (ICE) (All Other)

In April 2010, we sold our remaining 138,000 shares of ICE and recognized a $16 million gain ($10 million, net of tax). We recorded the gain in Interest and Investment Income on our Consolidated Statements of Income for the year ended December 31, 2010.

2009

Electric Transmission Texas LLC (ETT) (Utility Operations segment)

In 2009, TCC and TNC sold, at cost, $93 million and $2 million, respectively, of transmission facilities to ETT.

2008

None

DISCONTINUED OPERATIONS

Management periodically assesses our overall business model and makes decisions regarding our continued support and funding of our various businesses and operations. When it is determined that we will seek to exit a particular business or activity and we have met the accounting requirements for reclassification, we will reclassify those businesses or activities as discontinued operations. The assets and liabilities of these discontinued operations are classified in Assets Held for Sale and Liabilities Held for Sale until the time that they are sold.

Certain of our operations were discontinued in 2008. Results of operations of these businesses are classified as shown in the following table:

	U.K. Generation (a) (in millions)
2010 Revenue	$ -
2010 Pretax Income	-
2010 Earnings, Net of Tax	-
2009 Revenue	$ -
2009 Pretax Income	-
2009 Earnings, Net of Tax	-
2008 Revenue	$ 2
2008 Pretax Income	2
2008 Earnings, Net of Tax	12

(a) The 2008 amounts relate primarily to favorable income tax reserve adjustments.

8. BENEFIT PLANS

For a discussion of investment strategy, investment limitations, target asset allocations and the classification of investments within the fair value hierarchy, see "Investments Held in Trust for Future Liabilities" and "Fair Value Measurements of Assets and Liabilities" sections of Note 1.

We sponsor a qualified pension plan and two unfunded nonqualified pension plans. Substantially all of our employees are covered by the qualified plan or both the qualified and a nonqualified pension plan. We sponsor OPEB plans to provide medical and life insurance benefits for retired employees.

We recognize the funded status associated with our defined benefit pension and OPEB plans in the balance sheets. Disclosures about the plans are required by the "Compensation – Retirement Benefits" accounting guidance. We recognize an asset for a plan's overfunded status or a liability for a plan's underfunded status, and recognize, as a component of other comprehensive income, the changes in the funded status of the plan that arise during the year that are not recognized as a component of net periodic benefit cost. We record a regulatory asset instead of other comprehensive income for qualifying benefit costs of our regulated operations that for ratemaking purposes are deferred for future recovery. The cumulative funded status adjustment is equal to the remaining unrecognized deferrals for unamortized actuarial losses or gains, prior service costs and transition obligations, such that remaining deferred costs result in an AOCI equity reduction or regulatory asset and deferred gains result in an AOCI equity addition or regulatory liability.

Actuarial Assumptions for Benefit Obligations

The weighted-average assumptions as of December 31 of each year used in the measurement of our benefit obligations are shown in the following table:

	Pension Plans		Other Postretirement Benefit Plans	
Assumptions	**2010**	**2009**	**2010**	**2009**
Discount Rate	5.05 %	5.60 %	5.25 %	5.85 %
Rate of Compensation Increase	4.95 % (a)	4.60 % (a)	N/A	N/A

(a) Rates are for base pay only. In addition, an amount is added to reflect target incentive compensation for exempt employees and overtime and incentive pay for nonexempt employees.

N/A Not applicable

We use a duration-based method to determine the discount rate for our plans. A hypothetical portfolio of high quality corporate bonds similar to those included in the Moody's Aa bond index is constructed with a duration matching the benefit plan liability. The composite yield on the hypothetical bond portfolio is used as the discount rate for the plan.

For 2010, the rate of compensation increase assumed varies with the age of the employee, ranging from 3.5% per year to 11.5% per year, with an average increase of 4.95%.

Actuarial Assumptions for Net Periodic Benefit Costs

The weighted-average assumptions as of January 1 of each year used in the measurement of our benefit costs are shown in the following table:

	Pension Plans			Other Postretirement Benefit Plans		
	2010	**2009**	**2008**	**2010**	**2009**	**2008**
Discount Rate	5.60 %	6.00 %	6.00 %	5.85 %	6.10 %	6.20 %
Expected Return on Plan Assets	8.00 %	8.00 %	8.00 %	8.00 %	7.75 %	8.00 %
Rate of Compensation Increase	4.60 %	5.90 %	5.90 %	N/A	N/A	N/A

N/A Not Applicable

The expected return on plan assets for 2010 was determined by evaluating historical returns, the current investment climate (yield on fixed income securities and other recent investment market indicators), rate of inflation and current prospects for economic growth.

The health care trend rate assumptions as of January 1 of each year used for OPEB plans measurement purposes are shown below:

Health Care Trend Rates	2010	2009
Initial	8.00 %	6.50 %
Ultimate	5.00 %	5.00 %
Year Ultimate Reached	2016	2012

Assumed health care cost trend rates have a significant effect on the amounts reported for the OPEB health care plans. A 1% change in assumed health care cost trend rates would have the following effects:

	1% Increase	1% Decrease
	(in millions)	
Effect on Total Service and Interest Cost Components of Net Periodic Postretirement Health Care Benefit Cost	$ 22	$ (18)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	255	(209)

Significant Concentrations of Risk within Plan Assets

In addition to establishing the target asset allocation of plan assets, the investment policy also places restrictions on securities to limit significant concentrations within plan assets. The investment policy establishes guidelines that govern maximum market exposure, security restrictions, prohibited asset classes, prohibited types of transactions, minimum credit quality, average portfolio credit quality, portfolio duration and concentration limits. The guidelines were established to mitigate the risk of loss due to significant concentrations in any investment. We monitor the plans to control security diversification and ensure compliance with our investment policy. At December 31, 2010, the assets were invested in compliance with all investment limits. See "Investments Held in Trust for Future Liabilities" section of Note 1 for limit details.

Benefit Plan Obligations, Plan Assets and Funded Status as of December 31, 2010 and 2009

The following tables provide a reconciliation of the changes in the plans' benefit obligations, fair value of plan assets and funded status as of December 31. The benefit obligation for the defined benefit pension and OPEB plans are the projected benefit obligation and the accumulated benefit obligation, respectively.

	Pension Plans		Other Postretirement Benefit Plans	
	2010	2009	2010	2009
Change in Benefit Obligation	(in millions)			
Benefit Obligation at January 1	$ 4,701	$ 4,301	$ 1,941	$ 1,843
Service Cost	111	104	47	42
Interest Cost	253	254	113	110
Actuarial Loss	222	290	164	32
Plan Amendment Prior Service Credit	-	-	(36)	-
Benefit Payments	(480)	(248)	(142)	(120)
Participant Contributions	-	-	29	25
Medicare Subsidy	-	-	9	9
Benefit Obligation at December 31	$ 4,807	$ 4,701	$ 2,125	$ 1,941
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets at January 1	$ 3,403	$ 3,161	$ 1,308	$ 1,018
Actual Gain on Plan Assets	420	482	149	235
Company Contributions	515	8	117	150
Participant Contributions	-	-	29	25
Benefit Payments	(480)	(248)	(142)	(120)
Fair Value of Plan Assets at December 31	$ 3,858	$ 3,403	$ 1,461	$ 1,308
Underfunded Status at December 31	$ (949)	$ (1,298)	$ (664)	$ (633)

Benefit Amounts Recognized on the Balance Sheets as of December 31, 2010 and 2009

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2010	2009	2010	2009
	(in millions)			
Other Current Liabilities - Accrued Short-term Benefit Liability	$ (8)	$ (10)	$ (4)	$ (4)
Employee Benefits and Pension Obligations - Accrued Long-term Benefit Liability	(941)	(1,288)	(660)	(629)
Underfunded Status	$ (949)	$ (1,298)	$ (664)	$ (633)

Amounts Included in AOCI and Regulatory Assets as of December 31, 2010 and 2009

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2010	2009	2010	2009
Components	(in millions)			
Net Actuarial Loss	$ 2,129	$ 2,096	$ 638	$ 546
Prior Service Cost (Credit)	11	12	(20)	3
Transition Obligation	-	-	3	43
Recorded as				
Regulatory Assets	$ 1,764	$ 1,750	$ 388	$ 380
Deferred Income Taxes	132	125	81	74
Net of Tax AOCI	244	233	152	138

Components of the change in amounts included in AOCI and Regulatory Assets during the years ended December 31, 2010 and 2009 are as follows:

	Pension Plans		Other Postretirement Benefit Plans	
	Years Ended December 31,			
	2010	2009	2010	2009
Components	(in millions)			
Actuarial Loss (Gain) During the Year	$ 121	$ 130	$ 121	$ (127)
Prior Service Credit	-	-	(36)	-
Amortization of Actuarial Loss	(89)	(59)	(29)	(42)
Amortization of Transition Obligation	-	-	(27)	(27)
Change for the Year	$ 32	$ 71	$ 29	$ (196)

Pension and Other Postretirement Plans' Assets

The following table presents the classification of pension plan assets within the fair value hierarchy at December 31, 2010:

Asset Class	Level 1	Level 2	Level 3 (in millions)	Other	Total	Year End Allocation
Equities:						
Domestic	$ 1,350	$ 2	$ -	$ -	$ 1,352	35.1 %
International	403	-	-	-	403	10.4 %
Real Estate Investment Trusts	112	-	-	-	112	2.9 %
Common Collective Trust - International	-	163	-	-	163	4.2 %
Subtotal - Equities	1,865	165	-	-	2,030	52.6 %
Fixed Income:						
United States Government and Agency Securities	-	634	-	-	634	16.4 %
Corporate Debt	-	672	-	-	672	17.4 %
Foreign Debt	-	127	-	-	127	3.3 %
State and Local Government	-	23	-	-	23	0.6 %
Other - Asset Backed	-	51	-	-	51	1.3 %
Subtotal - Fixed Income	-	1,507	-	-	1,507	39.0 %
Real Estate	-	-	83	-	83	2.2 %
Alternative Investments	-	-	130	-	130	3.4 %
Securities Lending	-	254	-	-	254	6.6 %
Securities Lending Collateral (a)	-	-	-	(276)	(276)	(7.1)%
Cash and Cash Equivalents (b)	-	127	-	2	129	3.3 %
Other - Pending Transactions and Accrued Income (c)	-	-	-	1	1	- %
Total	$ 1,865	$ 2,053	$ 213	$ (273)	$ 3,858	100.0 %

(a) Amounts in "Other" column primarily represent an obligation to repay cash collateral received as part of the Securities Lending Program.
(b) Amounts in "Other" column primarily represent foreign currency holdings.
(c) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

The following table sets forth a reconciliation of changes in the fair value of real estate and alternative investments classified as Level 3 in the fair value hierarchy for AEP's pension assets:

	Real Estate	Alternative Investments (in millions)	Total Level 3
Balance as of January 1, 2010	$ 90	$ 106	$ 196
Actual Return on Plan Assets			
Relating to Assets Still Held as of the Reporting Date	(7)	4	(3)
Relating to Assets Sold During the Period	-	1	1
Purchases and Sales	-	19	19
Transfers into Level 3	-	-	-
Transfers out of Level 3	-	-	-
Balance as of December 31, 2010	$ 83	$ 130	$ 213

The following table presents the classification of OPEB plan assets within the fair value hierarchy at December 31, 2010:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 584	$ -	$ -	$ -	$ 584	40.0 %
International	220	-	-	-	220	15.1 %
Common Collective Trust - Global	-	115	-	-	115	7.9 %
Subtotal - Equities	804	115	-	-	919	63.0 %
Fixed Income:						
Common Collective Trust - Debt	-	48	-	-	48	3.3 %
United States Government and Agency Securities	-	93	-	-	93	6.4 %
Corporate Debt	-	110	-	-	110	7.5 %
Foreign Debt	-	25	-	-	25	1.7 %
State and Local Government	-	3	-	-	3	0.2 %
Other - Asset Backed	-	1	-	-	1	0.1 %
Subtotal - Fixed Income	-	280	-	-	280	19.2 %
Trust Owned Life Insurance:						
International Equities	-	49	-	-	49	3.3 %
United States Bonds	-	163	-	-	163	11.1 %
Cash and Cash Equivalents (a)	21	25	-	1	47	3.2 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	3	3	0.2 %
Total	$ 825	$ 632	$ -	$ 4	$ 1,461	100.0 %

(a) Amounts in "Other" column primarily represent foreign currency holdings.
(b) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

The following table presents the classification of pension plan assets within the fair value hierarchy at December 31, 2009:

Asset Class	Level 1	Level 2	Level 3 (in millions)	Other	Total	Year End Allocation
Equities:						
Domestic	$ 1,219	$ -	$ -	$ -	$ 1,219	35.8 %
International	320	-	-	-	320	9.4 %
Real Estate Investment Trusts	87	-	-	-	87	2.6 %
Common Collective Trust - International	-	161	-	-	161	4.7 %
Subtotal - Equities	1,626	161	-	-	1,787	52.5 %
Fixed Income:						
United States Government and Agency Securities	-	233	-	-	233	6.9 %
Corporate Debt	-	831	-	-	831	24.4 %
Foreign Debt	-	171	-	-	171	5.0 %
State and Local Government	-	35	-	-	35	1.0 %
Other - Asset Backed	-	27	-	-	27	0.8 %
Subtotal - Fixed Income	-	1,297	-	-	1,297	38.1 %
Real Estate	-	-	90	-	90	2.7 %
Alternative Investments	-	-	106	-	106	3.1 %
Securities Lending	-	173	-	-	173	5.1 %
Securities Lending Collateral (a)	-	-	-	(196)	(196)	(5.8)%
Cash and Cash Equivalents (b)	-	116	-	4	120	3.5 %
Other - Pending Transactions and Accrued Income (c)	-	-	-	26	26	0.8 %
Total	$ 1,626	$ 1,747	$ 196	$ (166)	$ 3,403	100.0 %

(a) Amounts in "Other" column primarily represent an obligation to repay cash collateral received as part of the Securities Lending Program.
(b) Amounts in "Other" column primarily represent foreign currency holdings.
(c) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

The following table sets forth a reconciliation of changes in the fair value of real estate and alternative investments classified as Level 3 in the fair value hierarchy for the pension assets:

	Real Estate	Alternative Investments (in millions)	Total Level 3
Balance as of January 1, 2009	$ 137	$ 106	$ 243
Actual Return on Plan Assets			
Relating to Assets Still Held as of the Reporting Date	(47)	(14)	(61)
Relating to Assets Sold During the Period	-	1	1
Purchases and Sales	-	13	13
Transfers in and/or out of Level 3	-	-	-
Balance as of December 31, 2009	$ 90	$ 106	$ 196

The following table presents the classification of OPEB plan assets within the fair value hierarchy at December 31, 2009:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 343	$ -	$ -	$ -	$ 343	26.2 %
International	375	-	-	-	375	28.7 %
Common Collective Trust - Global	-	93	-	-	93	7.1 %
Subtotal - Equities	718	93	-	-	811	62.0 %
Fixed Income:						
Common Collective Trust - Debt	-	38	-	-	38	2.9 %
United States Government and Agency Securities	-	42	-	-	42	3.2 %
Corporate Debt	-	141	-	-	141	10.8 %
Foreign Debt	-	32	-	-	32	2.4 %
State and Local Government	-	6	-	-	6	0.5 %
Other - Asset Backed	-	2	-	-	2	0.2 %
Subtotal - Fixed Income	-	261	-	-	261	20.0 %
Trust Owned Life Insurance:						
International Equities	-	75	-	-	75	5.7 %
United States Bonds	-	131	-	-	131	10.0 %
Cash and Cash Equivalents (a)	7	14	-	1	22	1.7 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	8	8	0.6 %
Total	$ 725	$ 574	$ -	$ 9	$ 1,308	100.0 %

(a) Amounts in "Other" column primarily represent foreign currency holdings.
(b) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

Determination of Pension Expense

We base our determination of pension expense or income on a market-related valuation of assets which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the market-related value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded.

Accumulated Benefit Obligation	December 31, 2010	2009
	(in millions)	
Qualified Pension Plan	$ 4,659	$ 4,539
Nonqualified Pension Plans	80	90
Total	$ 4,739	$ 4,629

For our underfunded pension plans that had an accumulated benefit obligation in excess of plan assets, the projected benefit obligation, accumulated benefit obligation and fair value of plan assets of these plans at December 31, 2010 and 2009 were as follows:

	Underfunded Pension Plans December 31, 2010	Underfunded Pension Plans December 31, 2009
	(in millions)	
Projected Benefit Obligation	$ 4,807	$ 4,701
Accumulated Benefit Obligation	$ 4,739	$ 4,629
Fair Value of Plan Assets	3,858	3,403
Underfunded Accumulated Benefit Obligation	$ (881)	$ (1,226)

Estimated Future Benefit Payments and Contributions

We expect contributions and payments for the pension plans of $158 million and the OPEB plans of $86 million during 2011. The estimated pension benefit payments for the unfunded plan and contributions to the trust are at least the minimum amount required by ERISA plus payment of unfunded nonqualified benefits. For the qualified pension plan, we may make additional discretionary contributions to maintain the funded status of the plan. The contribution to the OPEB plans is generally based on the amount of the OPEB plans' periodic benefit costs for accounting purposes as provided in agreements with state regulatory authorities, plus the additional discretionary contribution of our Medicare subsidy receipts.

The table below reflects the total benefits expected to be paid from the plan or from our assets, including both our share of the benefit cost and the participants' share of the cost, which is funded by participant contributions to the plan. Medicare subsidy receipts are shown in the year of the corresponding benefit payments, even though actual cash receipts are expected early in the following year. Future benefit payments are dependent on the number of employees retiring, whether the retiring employees elect to receive pension benefits as annuities or as lump sum distributions, future integration of the benefit plans with changes to Medicare and other legislation, future levels of interest rates and variances in actuarial results. The estimated payments for pension benefits and OPEB are as follows:

	Pension Plans	Other Postretirement Benefit Plans	
	Pension Payments	Benefit Payments	Medicare Subsidy Receipts
		(in millions)	
2011	$ 314	$ 143	$ 11
2012	320	148	12
2013	325	153	13
2014	333	160	14
2015	342	166	15
Years 2016 to 2020, in Total	1,811	931	95

Components of Net Periodic Benefit Cost

The following table provides the components of our net periodic benefit cost for the plans for the years ended December 31, 2010, 2009 and 2008:

	Pension Plans			Other Postretirement Benefit Plans		
	Years Ended December 31,					
	2010	2009	2008	2010	2009	2008
	(in millions)					
Service Cost	$ 111	$ 104	$ 100	$ 47	$ 42	$ 42
Interest Cost	253	254	249	113	110	113
Expected Return on Plan Assets	(312)	(321)	(336)	(105)	(80)	(111)
Amortization of Transition Obligation	-	-	-	27	27	27
Amortization of Prior Service Cost	-	-	1	-	-	-
Amortization of Net Actuarial Loss	89	59	37	29	42	9
Net Periodic Benefit Cost	141	96	51	111	141	80
Capitalized Portion	(44)	(30)	(16)	(35)	(44)	(25)
Net Periodic Benefit Cost Recognized as Expense	$ 97	$ 66	$ 35	$ 76	$ 97	$ 55

Estimated amounts expected to be amortized to net periodic benefit costs and the impact on the balance sheet during 2011 are shown in the following table:

Components	Pension Plans	Other Postretirement Benefit Plans
	(in millions)	
Net Actuarial Loss	$ 121	$ 33
Prior Service Cost (Credit)	1	(2)
Transition Obligation	-	2
Total Estimated 2011 Amortization	$ 122	$ 33
Expected to be Recorded as		
Regulatory Asset	$ 99	$ 19
Deferred Income Taxes	8	5
Net of Tax AOCI	15	9
Total	$ 122	$ 33

American Electric Power System Retirement Savings Plan

We sponsor the American Electric Power System Retirement Savings Plan, a defined contribution retirement savings plan for substantially all employees who are not members of the United Mine Workers of America (UMWA). It is a qualified plan offering participants an opportunity to contribute a portion of their pay with features under Section 401(k) of the Internal Revenue Code. We provided matching contributions of 75% of the first 6% of eligible compensation contributed by an employee in 2008. Effective January 1, 2009, we match the first 1% of eligible employee contributions at 100% and the next 5% of contributions at 70%. The cost for company matching contributions totaled $61 million in 2010, $74 million in 2009 and $71 million in 2008.

UMWA Benefits

We provide UMWA pension, health and welfare benefits for certain unionized mining employees, retirees and their survivors who meet eligibility requirements. UMWA trustees make final interpretive determinations with regard to all benefits. The pension benefits are administered by UMWA trustees and contributions are made to their trust funds. The health and welfare benefits are administered by us and benefits are paid from our general assets. Contributions and benefits paid were not material in 2010, 2009 and 2008.

9. BUSINESS SEGMENTS

Our primary business is our electric utility operations. Within our Utility Operations segment, we centrally dispatch generation assets and manage our overall utility operations on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight. While our Utility Operations segment remains our primary business segment, other segments include our AEP River Operations segment with significant barging activities and our Generation and Marketing segment, which includes our nonregulated generating, marketing and risk management activities primarily in the ERCOT market area and to a lesser extent Ohio in PJM and MISO. Intersegment sales and transfers are generally based on underlying contractual arrangements and agreements.

Our reportable segments and their related business activities are as follows:

Utility Operations

- Generation of electricity for sale to U.S. retail and wholesale customers.
- Electricity transmission and distribution in the U.S.

AEP River Operations

- Commercial barging operations that annually transport approximately 39 million tons of coal and dry bulk commodities primarily on the Ohio, Illinois and lower Mississippi Rivers. Approximately 46% of the barging is for transportation of agricultural products, 25% for coal, 11% for steel and 18% for other commodities.

Generation and Marketing

- Wind farms and marketing and risk management activities primarily in ERCOT and to a lesser extent Ohio in PJM and MISO.

The remainder of our activities is presented as All Other. While not considered a business segment, All Other includes:

- Parent's guarantee revenue received from affiliates, investment income, interest income and interest expense, and other nonallocated costs.
- Tax and interest expense adjustments related to our UK operations which were sold in 2004 and 2002.
- Forward natural gas contracts that were not sold with our natural gas pipeline and storage operations in 2004 and 2005. These contracts are financial derivatives which settle and expire in 2011.
- The 2008 cash settlement of a purchase power and sale agreement with TEM related to the Plaquemine Cogeneration Facility which was sold in 2006.
- Revenue sharing related to the Plaquemine Cogeneration Facility.

The tables below present our reportable segment information for years ended December 31, 2010, 2009 and 2008 and balance sheet information as of December 31, 2010 and 2009. These amounts include certain estimates and allocations where necessary.

	Utility Operations	Nonutility Operations: AEP River Operations	Nonutility Operations: Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
			(in millions)			
Year Ended December 31, 2010						
Revenues from:						
External Customers	$ 13,687	$ 566	$ 173	$ 1	$ -	$ 14,427
Other Operating Segments	104	22	-	14	(140)	-
Total Revenues	$ 13,791	$ 588	$ 173	$ 15	$ (140)	$ 14,427
Depreciation and Amortization	$ 1,598	$ 24	$ 30	$ 2	$ (13)(b)	$ 1,641
Interest Income	8	-	2	31	(20)	21
Interest Expense	942	14	20	58	(35)(b)	999
Income Tax Expense (Credit)	650	19	(20)	(6)	-	643
Net Income (Loss)	1,201	37	25	(45)	-	1,218
Gross Property Additions	2,475	23	1	1	-	2,500

	Utility Operations	Nonutility Operations: AEP River Operations	Nonutility Operations: Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
			(in millions)			
Year Ended December 31, 2009						
Revenues from:						
External Customers	$ 12,733 (e)	$ 490	$ 281	$ (15)	$ -	$ 13,489
Other Operating Segments	70 (e)	18	5	36	(129)	-
Total Revenues	$ 12,803	$ 508	$ 286	$ 21	$ (129)	$ 13,489
Depreciation and Amortization	$ 1,561	$ 17	$ 29	$ 2	$ (12)(b)	$ 1,597
Interest Income	4	-	-	47	(40)	11
Interest Expense	916	5	21	86	(55)(b)	973
Income Tax Expense (Credit)	553	23	-	(1)	-	575
Income (Loss) Before Discontinued Operations and Extraordinary Loss	$ 1,329	$ 47	$ 41	$ (47)	$ -	$ 1,370
Extraordinary Loss, Net of Tax	(5)	-	-	-	-	(5)
Net Income (Loss)	$ 1,324	$ 47	$ 41	$ (47)	$ -	$ 1,365
Gross Property Additions	$ 2,813	$ 81	$ 1	$ 1	$ -	$ 2,896

	Utility Operations	Nonutility Operations: AEP River Operations	Nonutility Operations: Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
	(in millions)					
Year Ended December 31, 2008						
Revenues from:						
External Customers	$ 13,326 (e)	$ 616	$ 485	$ 13	$ -	$ 14,440
Other Operating Segments	240 (e)	30	(122)	9	(157)	-
Total Revenues	$ 13,566	$ 646	$ 363	$ 22	$ (157)	$ 14,440
Depreciation and Amortization	$ 1,450	$ 14	$ 28	$ 2	$ (11)(b)	$ 1,483
Interest Income	42	-	1	78	(65)	56
Interest Expense	915	5	22	94	(79)(b)	957
Income Tax Expense	515	26	17	84	-	642
Income Before Discontinued Operations and Extraordinary Loss	$ 1,123	$ 55	$ 65	$ 133	$ -	$ 1,376
Discontinued Operations, Net of Tax	-	-	-	12	-	12
Net Income	$ 1,123	$ 55	$ 65	$ 145	$ -	$ 1,388
Gross Property Additions	$ 3,871	$ 116	$ 2	$ (29)(c)	$ -	$ 3,960

	Utility Operations	Nonutility Operations: AEP River Operations	Nonutility Operations: Generation and Marketing	All Other (a)	Reconciling Adjustments (b)	Consolidated
	(in millions)					
December 31, 2010						
Total Property, Plant and Equipment	$ 52,822	$ 574	$ 584	$ 11	$ (251)	$ 53,740
Accumulated Depreciation and Amortization	17,795	110	198	9	(46)	18,066
Total Property, Plant and Equipment - Net	$ 35,027	$ 464	$ 386	$ 2	$ (205)	$ 35,674
Total Assets	$ 48,780	$ 621	$ 881	$ 15,942	$ (15,769) (d)	$ 50,455
Investments in Equity Method Investees	157	3	-	-	-	160

	Utility Operations	Nonutility Operations: AEP River Operations	Nonutility Operations: Generation and Marketing	All Other (a)	Reconciling Adjustments (b)	Consolidated
	(in millions)					
December 31, 2009						
Total Property, Plant and Equipment	$ 50,905	$ 436	$ 571	$ 10	$ (238)	$ 51,684
Accumulated Depreciation and Amortization	17,110	88	168	8	(34)	17,340
Total Property, Plant and Equipment - Net	$ 33,795	$ 348	$ 403	$ 2	$ (204)	$ 34,344
Total Assets	$ 46,930	$ 495	$ 779	$ 15,094	$ (14,950) (d)	$ 48,348
Investments in Equity Method Investees	84	4	-	-	-	88

(a) All Other includes:

- Parent's guarantee revenue received from affiliates, investment income, interest income and interest expense, and other nonallocated costs.
- Tax and interest expense adjustments related to our UK operations which were sold in 2004 and 2002.
- Forward natural gas contracts that were not sold with our natural gas pipeline and storage operations in 2004 and 2005. These contracts are financial derivatives which settle and expire in 2011.
- The 2008 cash settlement of a purchase power and sale agreement with TEM related to the Plaquemine Cogeneration Facility which was sold in 2006. The cash settlement of $255 million ($164 million, net of tax) is included in Net Income.
- Revenue sharing related to the Plaquemine Cogeneration Facility.

(b) Includes eliminations due to an intercompany capital lease.

(c) Gross Property Additions for All Other includes construction expenditures of $8 million in 2008 related to the acquisition of turbines by one of our nonregulated, wholly-owned subsidiaries. These turbines were refurbished and transferred to a generating facility within our Utility Operations segment in the fourth quarter of 2008. The transfer of these turbines resulted in the elimination of $37 million from All Other and the addition of $37 million to Utility Operations.

(d) Reconciling Adjustments for Total Assets primarily include the elimination of intercompany advances to affiliates and intercompany accounts receivable along with the elimination of AEP's investments in subsidiary companies.

(e) PSO and SWEPCo transferred certain existing ERCOT energy marketing contracts to AEP Energy Partners, Inc. (AEPEP) (Generation and Marketing segment) and entered into intercompany financial and physical purchase and sales agreements with AEPEP. As a result, we reported third-party net purchases or sales activity for these energy marketing contracts as Revenues from External Customers for the Utility Operations segment. This was offset by the Utility Operations segment's related net sales (purchases) for these contracts with AEPEP in Revenues from Other Operating Segments of $(5) million and $122 million for the years ended December 31, 2009 and 2008, respectively. The Generation and Marketing segment also reported these purchase or sales contracts with Utility Operations as Revenues from Other Operating Segments. These affiliated contracts between PSO and SWEPCo with AEPEP ended in December 2009.

10. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

We are exposed to certain market risks as a major power producer and marketer of wholesale electricity, coal and emission allowances. These risks include commodity price risk, interest rate risk, credit risk and, to a lesser extent, foreign currency exchange risk. These risks represent the risk of loss that may impact us due to changes in the underlying market prices or rates. We manage these risks using derivative instruments.

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Trading Strategies

Our strategy surrounding the use of derivative instruments for trading purposes focuses on seizing market opportunities to create value driven by expected changes in the market prices of the commodities in which we transact.

Risk Management Strategies

Our strategy surrounding the use of derivative instruments focuses on managing our risk exposures, future cash flows and creating value utilizing both economic and formal hedging strategies. To accomplish our objectives, we primarily employ risk management contracts including physical forward purchase and sale contracts, financial forward purchase and sale contracts and financial swap instruments. Not all risk management contracts meet the definition of a derivative under the accounting guidance for "Derivatives and Hedging." Derivative risk management contracts elected normal under the normal purchases and normal sales scope exception are not subject to the requirements of this accounting guidance.

We enter into power, coal, natural gas, interest rate and, to a lesser degree, heating oil and gasoline, emission allowance and other commodity contracts to manage the risk associated with our energy business. We enter into interest rate derivative contracts in order to manage the interest rate exposure associated with our commodity portfolio. For disclosure purposes, such risks are grouped as "Commodity," as they are related to energy risk management activities. We also engage in risk management of interest rate risk associated with debt financing and foreign currency risk associated with future purchase obligations denominated in foreign currencies. For disclosure purposes, these risks are grouped as "Interest Rate and Foreign Currency." The amount of risk taken is determined by the Commercial Operations and Finance groups in accordance with our established risk management policies as approved by the Finance Committee of our Board of Directors.

The following table represents the gross notional volume of our outstanding derivative contracts as of December 31, 2010 and 2009:

Notional Volume of Derivative Instruments

	Volume December 31, 2010	Volume December 31, 2009	Unit of Measure
	(in millions)		
Commodity:			
Power	652	589	MWHs
Coal	63	60	Tons
Natural Gas	94	127	MMBtus
Heating Oil and Gasoline	6	6	Gallons
Interest Rate	$ 171	$ 216	USD
Interest Rate and Foreign Currency	$ 907	$ 83	USD

Fair Value Hedging Strategies

We enter into interest rate derivative transactions as part of an overall strategy to manage the mix of fixed-rate and floating-rate debt. Certain interest rate derivative transactions effectively modify our exposure to interest rate risk by converting a portion of our fixed-rate debt to a floating rate. Provided specific criteria are met, these interest rate derivatives are designated as fair value hedges.

Cash Flow Hedging Strategies

We enter into and designate as cash flow hedges certain derivative transactions for the purchase and sale of power, coal, natural gas and heating oil and gasoline ("Commodity") in order to manage the variable price risk related to the forecasted purchase and sale of these commodities. We monitor the potential impacts of commodity price changes and, where appropriate, enter into derivative transactions to protect profit margins for a portion of future electricity sales and fuel or energy purchases. We do not hedge all commodity price risk.

Our vehicle fleet and barge operations are exposed to gasoline and diesel fuel price volatility. We enter into financial heating oil and gasoline derivative contracts in order to mitigate price risk of our future fuel purchases. For disclosure purposes, these contracts are included with other hedging activity as "Commodity." We do not hedge all fuel price risk.

We enter into a variety of interest rate derivative transactions in order to manage interest rate risk exposure. Some interest rate derivative transactions effectively modify our exposure to interest rate risk by converting a portion of our floating-rate debt to a fixed rate. We also enter into interest rate derivative contracts to manage interest rate exposure related to anticipated borrowings of fixed-rate debt. Our anticipated fixed-rate debt offerings have a high probability of occurrence as the proceeds will be used to fund existing debt maturities and projected capital expenditures. We do not hedge all interest rate exposure.

At times, we are exposed to foreign currency exchange rate risks primarily when we purchase certain fixed assets from foreign suppliers. In accordance with our risk management policy, we may enter into foreign currency derivative transactions to protect against the risk of increased cash outflows resulting from a foreign currency's appreciation against the dollar. We do not hedge all foreign currency exposure.

ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND THE IMPACT ON OUR FINANCIAL STATEMENTS

The accounting guidance for "Derivatives and Hedging" requires recognition of all qualifying derivative instruments as either assets or liabilities in the balance sheet at fair value. The fair values of derivative instruments accounted for using MTM accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data and assumptions. In order to determine the relevant fair values of our derivative instruments, we also apply valuation adjustments for discounting, liquidity and credit quality.

Credit risk is the risk that a counterparty will fail to perform on the contract or fail to pay amounts due. Liquidity risk represents the risk that imperfections in the market will cause the price to vary from estimated fair value based upon prevailing market supply and demand conditions. Since energy markets are imperfect and volatile, there are inherent risks related to the underlying assumptions in models used to fair value risk management contracts. Unforeseen events may cause reasonable price curves to differ from actual price curves throughout a contract's term and at the time a contract settles. Consequently, there could be significant adverse or favorable effects on future net income and cash flows if market prices are not consistent with our estimates of current market consensus for forward prices in the current period. This is particularly true for longer term contracts. Cash flows may vary based on market conditions, margin requirements and the timing of settlement of our risk management contracts.

According to the accounting guidance for "Derivatives and Hedging," we reflect the fair values of our derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, we are required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the December 31, 2010 and 2009 balance sheets, we netted $8 million and $12 million, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and $109 million and $98 million, respectively, of cash collateral paid to third parties against short-term and long-term risk management liabilities.

The following tables represent the gross fair value impact of our derivative activity on our Consolidated Balance Sheets as of December 31, 2010 and 2009:

Fair Value of Derivative Instruments
December 31, 2010

Balance Sheet Location	Risk Management Contracts: Commodity (a)	Hedging Contracts: Commodity (a)	Hedging Contracts: Interest Rate and Foreign Currency (a)(c)	Other (a) (b)	Total
		(in millions)			
Current Risk Management Assets	$ 1,023	$ 18	$ 30	$ (839)	$ 232
Long-term Risk Management Assets	546	12	2	(150)	410
Total Assets	1,569	30	32	(989)	642
Current Risk Management Liabilities	995	13	2	(881)	129
Long-term Risk Management Liabilities	387	6	3	(255)	141
Total Liabilities	1,382	19	5	(1,136)	270
Total MTM Derivative Contract Net Assets (Liabilities)	$ 187	$ 11	$ 27	$ 147	$ 372

Fair Value of Derivative Instruments
December 31, 2009

Balance Sheet Location	Risk Management Contracts: Commodity (a)	Hedging Contracts: Commodity (a)	Hedging Contracts: Interest Rate and Foreign Currency (a)	Other (a) (b)	Total
		(in millions)			
Current Risk Management Assets	$ 1,078	$ 13	$ -	$ (831)	$ 260
Long-term Risk Management Assets	614	-	-	(271)	343
Total Assets	1,692	13	-	(1,102)	603
Current Risk Management Liabilities	997	17	3	(897)	120
Long-term Risk Management Liabilities	442	-	2	(316)	128
Total Liabilities	1,439	17	5	(1,213)	248
Total MTM Derivative Contract Net Assets (Liabilities)	$ 253	$ (4)	$ (5)	$ 111	$ 355

(a) Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented on the Consolidated Balance Sheet on a net basis in accordance with the accounting guidance for "Derivatives and Hedging."

(b) Amounts represent counterparty netting of risk management and hedging contracts, associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging" and dedesignated risk management contracts.

(c) At December 31, 2010, Risk Management Assets included $7 million and Risk Management Liabilities included $1 million related to fair value hedging strategies while the remainder related to cash flow hedging strategies. At December 31, 2009, we only employed cash flow hedging strategies.

The table below presents our activity of derivative risk management contracts for the years ended December 31, 2010 and 2009:

Amount of Gain (Loss) Recognized on Risk Management Contracts

Location of Gain (Loss)	Years Ended December 31, 2010	2009
	(in millions)	
Utility Operations Revenue	$ 85	$ 144
Other Revenue	9	19
Regulatory Assets (a)	(9)	(28)
Regulatory Liabilities (a)	38	(7)
Total Gain (Loss) on Risk Management Contracts	$ 123	$ 128

(a) Represents realized and unrealized gains and losses subject to regulatory accounting treatment recorded as either current or noncurrent on the balance sheet.

Certain qualifying derivative instruments have been designated as normal purchase or normal sale contracts, as provided in the accounting guidance for "Derivatives and Hedging." Derivative contracts that have been designated as normal purchases or normal sales under that accounting guidance are not subject to MTM accounting treatment and are recognized on the Consolidated Statements of Income on an accrual basis.

Our accounting for the changes in the fair value of a derivative instrument depends on whether it qualifies for and has been designated as part of a hedging relationship and further, on the type of hedging relationship. Depending on the exposure, we designate a hedging instrument as a fair value hedge or a cash flow hedge.

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in Revenues on a net basis on the Consolidated Statements of Income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in Revenues or Expenses on the Consolidated Statements of Income depending on the relevant facts and circumstances. However, unrealized and some realized gains and losses in regulated jurisdictions for both trading and non-trading derivative instruments are recorded as regulatory assets (for losses) or regulatory liabilities (for gains) in accordance with the accounting guidance for "Regulated Operations."

Accounting for Fair Value Hedging Strategies

For fair value hedges (i.e. hedging the exposure to changes in the fair value of an asset, liability or an identified portion thereof attributable to a particular risk), the gain or loss on the derivative instrument as well as the offsetting gain or loss on the hedged item associated with the hedged risk impacts Net Income during the period of change.

We record realized and unrealized gains or losses on interest rate swaps that qualify for fair value hedge accounting treatment and any offsetting changes in the fair value of the debt being hedged in Interest Expense on our Consolidated Statements of Income. During 2010, we recognized gains of $6 million on our hedging instruments, offsetting losses of $6 million on our long-term debt and an immaterial amount of hedge ineffectiveness. During 2009, we did not employ any fair value hedging strategies. During 2008, we employed fair value hedging strategies and recognized an immaterial loss and no hedge ineffectiveness.

Accounting for Cash Flow Hedging Strategies

For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows attributable to a particular risk), we initially report the effective portion of the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income (Loss) on our Consolidated Balance Sheets until the period the hedged item affects Net Income. We recognize any hedge ineffectiveness in Net Income immediately during the period of change, except in regulated jurisdictions where hedge ineffectiveness is recorded as a regulatory asset (for losses) or a regulatory liability (for gains).

Realized gains and losses on derivative contracts for the purchase and sale of power, coal, natural gas, and heating oil and gasoline designated as cash flow hedges are included in Revenues, Fuel and Other Consumables Used for Electric Generation or Purchased Electricity for Resale on our Consolidated Statements of Income, or in Regulatory Assets or Regulatory Liabilities on our Consolidated Balance Sheets, depending on the specific nature of the risk being hedged. During 2010, 2009 and 2008, we designated commodity derivatives as cash flow hedges.

We reclassify gains and losses on financial fuel derivative contracts designated as cash flow hedges from Accumulated Other Comprehensive Income (Loss) on our Consolidated Balance Sheets into Other Operation expense, Maintenance expense or Depreciation and Amortization expense, as it relates to capital projects, on our Consolidated Statements of Income. During 2010 and 2009, we designated heating oil and gasoline derivatives as cash flow hedges.

We reclassify gains and losses on interest rate derivative hedges related to our debt financings from Accumulated Other Comprehensive Income (Loss) into Interest Expense in those periods in which hedged interest payments occur. During 2010, 2009 and 2008, we designated interest rate derivatives as cash flow hedges.

The accumulated gains or losses related to our foreign currency hedges are reclassified from Accumulated Other Comprehensive Income (Loss) on our Consolidated Balance Sheets into Depreciation and Amortization expense on our Consolidated Statements of Income over the depreciable lives of the fixed assets designated as the hedged items in qualifying foreign currency hedging relationships. During 2010, 2009 and 2008, we designated foreign currency derivatives as cash flow hedges.

During 2009, we recognized a $6 million gain in Interest Expense related to hedge ineffectiveness on interest rate derivatives designated in cash flow hedge strategies. During 2010, 2009 and 2008, hedge ineffectiveness was immaterial or nonexistent for all of the other hedge strategies disclosed above.

The following tables provide details on designated, effective cash flow hedges included in AOCI on our Consolidated Balance Sheets and the reasons for changes in cash flow hedges for the years ended December 31, 2010 and 2009. All amounts in the following tables are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
Year Ended December 31, 2010

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Balance in AOCI as of December 31, 2009	$ (2)	$ (13)	$ (15)
Changes in Fair Value Recognized in AOCI	9	13	22
Amount of (Gain) or Loss Reclassified from AOCI to Income Statement/within Balance Sheet:			
Utility Operations Revenue	-	-	-
Other Revenue	(7)	-	(7)
Purchased Electricity for Resale	4	-	4
Interest Expense	-	4	4
Regulatory Assets (a)	3	-	3
Regulatory Liabilities (a)	-	-	-
Balance in AOCI as of December 31, 2010	$ 7	$ 4	$ 11

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
Year Ended December 31, 2009

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Balance in AOCI as of December 31, 2008	$ 7	$ (29)	$ (22)
Changes in Fair Value Recognized in AOCI	(6)	11	5
Amount of (Gain) or Loss Reclassified from AOCI to Income Statement/within Balance Sheet:			
Utility Operations Revenue	(15)	-	(15)
Other Revenue	(15)	-	(15)
Purchased Electricity for Resale	29	-	29
Interest Expense	-	5	5
Regulatory Assets (a)	5	-	5
Regulatory Liabilities (a)	(7)	-	(7)
Balance in AOCI as of December 31, 2009	$ (2)	$ (13)	$ (15)

(a) Represents realized and unrealized gains and losses subject to regulatory accounting treatment recorded as either current or noncurrent on the balance sheets.

During 2008 we reclassified $7 million of gains from AOCI to net income.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on our Consolidated Balance Sheets at December 31, 2010 and 2009 were:

Impact of Cash Flow Hedges on our Consolidated Balance Sheet
December 31, 2010

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Hedging Assets (a)	$ 13	$ 25	$ 38
Hedging Liabilities (a)	(2)	(4)	(6)
AOCI Gain (Loss) Net of Tax	7	4	11
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	3	(2)	1

Impact of Cash Flow Hedges on our Consolidated Balance Sheet
December 31, 2009

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Hedging Assets (a)	$ 8	$ -	$ 8
Hedging Liabilities (a)	(12)	(5)	(17)
AOCI Gain (Loss) Net of Tax	(2)	(13)	(15)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	(2)	(4)	(6)

(a) Hedging Assets and Hedging Liabilities are included in Risk Management Assets and Liabilities on our Consolidated Balance Sheets.

The actual amounts that we reclassify from Accumulated Other Comprehensive Income (Loss) to Net Income can differ from the estimate above due to market price changes. As of December 31, 2010, the maximum length of time that we are hedging (with contracts subject to the accounting guidance for "Derivatives and Hedging") our exposure to variability in future cash flows related to forecasted transactions is 41 months.

Credit Risk

We limit credit risk in our wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. We use Moody's, Standard and Poor's and current market-based qualitative and quantitative data as well as financial statements to assess the financial health of counterparties on an ongoing basis.

We use standardized master agreements which may include collateral requirements. These master agreements facilitate the netting of cash flows associated with a single counterparty. Cash, letters of credit and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. The collateral agreements require a counterparty to post cash or letters of credit in the event an exposure exceeds our established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with our credit policy. In addition, collateral agreements allow for termination and liquidation of all positions in the event of a failure or inability to post collateral.

Collateral Triggering Events

Under the tariffs of the RTOs and Independent System Operators (ISOs) and a limited number of derivative and non-derivative contracts primarily related to our competitive retail auction loads, we are obligated to post an additional amount of collateral if our credit ratings decline below investment grade. The amount of collateral required fluctuates based on market prices and our total exposure. On an ongoing basis, our risk management organization assesses the appropriateness of these collateral triggering items in contracts. We do not anticipate a downgrade below investment grade. The following table represents: (a) our aggregate fair value of such derivative contracts, (b) the amount of collateral we would have been required to post for all derivative and non-derivative contracts if our credit ratings had declined below investment grade and (c) how much was attributable to RTO and ISO activities as of December 31, 2010 and 2009:

	December 31, 2010	December 31, 2009
	(in millions)	
Liabilities for Derivative Contracts with Credit Downgrade Triggers	$ 20	$ 10
Amount of Collateral AEP Subsidiaries Would Have Been Required to Post	45	34
Amount Attributable to RTO and ISO Activities	44	29

In addition, a majority of our non-exchange traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event under outstanding debt in excess of $50 million. On an ongoing basis, our risk management organization assesses the appropriateness of these cross-default provisions in our contracts. We do not anticipate a non-performance event under these provisions. The following table represents: (a) the fair value of these derivative liabilities subject to cross-default provisions prior to consideration of contractual netting arrangements, (b) the amount this exposure has been reduced by cash collateral we have posted and (c) if a cross-default provision would have been triggered, the settlement amount that would be required after considering our contractual netting arrangements as of December 31, 2010 and 2009:

	December 31, 2010	December 31, 2009
	(in millions)	
Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	$ 401	$ 567
Amount of Cash Collateral Posted	81	15
Additional Settlement Liability if Cross Default Provision is Triggered	213	199

11. FAIR VALUE MEASUREMENTS

Fair Value Measurements of Long-term Debt

The fair values of Long-term Debt are based on quoted market prices, without credit enhancements, for the same or similar issues and the current interest rates offered for instruments with similar maturities. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that we could realize in a current market exchange.

The book values and fair values of Long-term Debt as of December 31, 2010 and 2009 are summarized in the following table:

	December 31, 2010		December 31, 2009	
	Book Value	Fair Value	Book Value	Fair Value
	(in millions)			
Long-term Debt	$ 16,811	$ 18,285	$ 17,498	$ 18,479

Fair Value Measurements of Other Temporary Investments

Other Temporary Investments include marketable securities that we intend to hold for less than one year, investments by our protected cell of EIS and funds held by trustees primarily for the payment of debt. See "Other Temporary Investments" section of Note 1.

The following is a summary of Other Temporary Investments:

Other Temporary Investments	December 31, 2010 Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
	(in millions)			
Restricted Cash (a)	$ 225	$ -	$ -	$ 225
Fixed Income Securities:				
Mutual Funds	69	-	-	69
Variable Rate Demand Notes	97	-	-	97
Equity Securities - Mutual Funds	18	7	-	25
Total Other Temporary Investments	$ 409	$ 7	$ -	$ 416

Other Temporary Investments	December 31, 2009 Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
	(in millions)			
Restricted Cash (a)	$ 223	$ -	$ -	$ 223
Fixed Income Securities:				
Mutual Funds	57	-	-	57
Variable Rate Demand Notes	45	-	-	45
Equity Securities:				
Domestic	1	15	-	16
Mutual Funds	18	4	-	22
Total Other Temporary Investments	$ 344	$ 19	$ -	$ 363

(a) Primarily represents amounts held for the payment of debt.

The following table provides the activity for our debt and equity securities within Other Temporary Investments for the years ended December 31, 2010, 2009 and 2008:

	Years Ended December 31, 2010	2009	2008
	(in millions)		
Proceeds From Investment Sales	$ 455	$ 35	$ 1,185
Purchases of Investments	503	82	1,118
Gross Realized Gains on Investment Sales	16	-	-
Gross Realized Losses on Investment Sales	-	-	-

At December 31, 2010 and 2009, we had no Other Temporary Investments with an unrealized loss position. In June 2009, we recorded $9 million ($6 million, net of tax) of other-than-temporary impairments of Other Temporary Investments for equity investments of our protected cell captive insurance company. At December 31, 2010, the fair value of fixed income securities are primarily debt based mutual funds with short and intermediate maturities and variable rate demand notes. Mutual funds may be sold and do not contain maturity dates.

Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal

I&M records securities held in trust funds for decommissioning nuclear facilities and for the disposal of SNF at fair value. See "Nuclear Trust Funds" section of Note 1.

The following is a summary of nuclear trust fund investments at December 31, 2010 and December 31, 2009:

	December 31,					
	2010			2009		
	Estimated Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments	Estimated Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments
	(in millions)					
Cash and Cash Equivalents	$ 20	$ -	$ -	$ 14	$ -	$ -
Fixed Income Securities:						
United States Government	461	23	(1)	401	13	(4)
Corporate Debt	59	4	(2)	57	5	(2)
State and Local Government	341	(1)	-	369	8	1
Subtotal Fixed Income Securities	861	26	(3)	827	26	(5)
Equity Securities - Domestic	634	183	(123)	551	234	(119)
Spent Nuclear Fuel and Decommissioning Trusts	$ 1,515	$ 209	$ (126)	$ 1,392	$ 260	$ (124)

The following table provides the securities activity within the decommissioning and SNF trusts for the years ended December 31, 2010, 2009 and 2008:

	Years Ended December 31,		
	2010	2009	2008
	(in millions)		
Proceeds From Investment Sales	$ 1,362	$ 713	$ 732
Purchases of Investments	1,415	771	804
Gross Realized Gains on Investment Sales	12	28	33
Gross Realized Losses on Investment Sales	2	1	7

The adjusted cost of debt securities was $835 million and $801 million as of December 31, 2010 and 2009, respectively.

The fair value of debt securities held in the nuclear trust funds, summarized by contractual maturities, at December 31, 2010 was as follows:

	Fair Value of Debt Securities
	(in millions)
Within 1 year	$ 22
1 year – 5 years	306
5 years – 10 years	257
After 10 years	276
Total	$ 861

Fair Value Measurements of Financial Assets and Liabilities

For a discussion of fair value accounting and the classification of assets and liabilities within the fair value hierarchy, see the "Fair Value Measurements of Assets and Liabilities" section of Note 1.

The following tables set forth, by level within the fair value hierarchy, our financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2010 and 2009. As required by the accounting guidance for "Fair Value Measurements and Disclosures," financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There have not been any significant changes in AEP's valuation techniques.

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2010

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Cash and Cash Equivalents (a)	$ 170	$ -	$ -	$ 124	$ 294
Other Temporary Investments					
Restricted Cash (a)	184	-	-	41	225
Fixed Income Securities:					
Mutual Funds	69	-	-	-	69
Variable Rate Demand Notes	-	97	-	-	97
Equity Securities - Mutual Funds (b)	25	-	-	-	25
Total Other Temporary Investments	278	97	-	41	416
Risk Management Assets					
Risk Management Commodity Contracts (c) (f)	20	1,432	112	(1,013)	551
Cash Flow Hedges:					
Commodity Hedges (c)	11	17	-	(15)	13
Fair Value Hedges	-	7	-	-	7
Interest Rate/Foreign Currency Hedges	-	25	-	-	25
Dedesignated Risk Management Contracts (d)	-	-	-	46	46
Total Risk Management Assets	31	1,481	112	(982)	642
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	-	8	-	12	20
Fixed Income Securities:					
United States Government	-	461	-	-	461
Corporate Debt	-	59	-	-	59
State and Local Government	-	341	-	-	341
Subtotal Fixed Income Securities	-	861	-	-	861
Equity Securities - Domestic (b)	634	-	-	-	634
Total Spent Nuclear Fuel and Decommissioning Trusts	634	869	-	12	1,515
Total Assets	$ 1,113	$ 2,447	$ 112	$ (805)	$ 2,867
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (f)	$ 25	$ 1,325	$ 27	$ (1,114)	$ 263
Cash Flow Hedges:					
Commodity Hedges (c)	4	13	-	(15)	2
Fair Value Hedges	-	1	-	-	1
Interest Rate/Foreign Currency Hedges	-	4	-	-	4
Total Risk Management Liabilities	$ 29	$ 1,343	$ 27	$ (1,129)	$ 270

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2009

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Cash and Cash Equivalents (a)	$ 427	$ -	$ -	$ 63	$ 490
Other Temporary Investments					
Restricted Cash (a)	198	-	-	25	223
Fixed Income Securities:					
Mutual Funds	57	-	-	-	57
Variable Rate Demand Notes	-	45	-	-	45
Equity Securities (b):					
Domestic	16	-	-	-	16
Mutual Funds	22	-	-	-	22
Total Other Temporary Investments	293	45	-	25	363
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	8	1,609	72	(1,119)	570
Cash Flow Hedges:					
Commodity Hedges (c)	1	11	-	(4)	8
Dedesignated Risk Management Contracts (d)	-	-	-	25	25
Total Risk Management Assets	9	1,620	72	(1,098)	603
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	-	3	-	11	14
Fixed Income Securities:					
United States Government	-	401	-	-	401
Corporate Debt	-	57	-	-	57
State and Local Government	-	369	-	-	369
Subtotal Fixed Income Securities	-	827	-	-	827
Equity Securities - Domestic (b)	551	-	-	-	551
Total Spent Nuclear Fuel and Decommissioning Trusts	551	830	-	11	1,392
Total Assets	$ 1,280	$ 2,495	$ 72	$ (999)	$ 2,848
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ 11	$ 1,415	$ 10	$ (1,205)	$ 231
Cash Flow Hedges:					
Commodity Hedges (c)	-	16	-	(4)	12
Interest Rate/Foreign Currency Hedges	-	5	-	-	5
Total Risk Management Liabilities	$ 11	$ 1,436	$ 10	$ (1,209)	$ 248

(a) Amounts in "Other" column primarily represent cash deposits in bank accounts with financial institutions or with third parties. Level 1 amounts primarily represent investments in money market funds.

(b) Amounts represent publicly traded equity securities and equity-based mutual funds.

(c) Amounts in "Other" column primarily represent counterparty netting of risk management and hedging contracts and associated cash collateral under the accounting guidance for "Derivatives and Hedging."

(d) Represents contracts that were originally MTM but were subsequently elected as normal under the accounting guidance for "Derivatives and Hedging." At the time of the normal election, the MTM value was frozen and no longer fair valued. This MTM value will be amortized into revenues over the remaining life of the contracts.

(e) Amounts in "Other" column primarily represent accrued interest receivables from financial institutions. Level 2 amounts primarily represent investments in money market funds.

(f) The December 31, 2010 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 1 matures ($2) million in 2011, $2 million in periods 2012-2014 and ($5) million in periods 2015-2018; Level 2 matures $13 million in 2011, $66 million in periods 2012-2014, $12 million in periods 2015-2016 and $16 million in periods 2017-2028; Level 3 matures $18 million in 2011, $24 million in periods 2012-2014, $16 million in periods 2015-2016 and $27 million in periods 2017-2028. Risk management commodity contracts are substantially comprised of power contracts.

(g) The December 31, 2009 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 1 matures ($1) million in 2010, ($1) million in periods 2011-2013 and ($1) million in periods 2014-2015; Level 2 matures $65 million in 2010, $84 million in periods 2011-2013, $22 million in periods 2014-2015 and $23 million in periods 2016-2028; Level 3 matures $17 million in 2010, $16 million in periods 2011-2013, $8 million in periods 2014-2015 and $21 million in periods 2016-2028.

There have been no transfers between Level 1 and Level 2 during the year ended December 31, 2010.

The following tables set forth a reconciliation of changes in the fair value of net trading derivatives and other investments classified as Level 3 in the fair value hierarchy:

Year Ended December 31, 2010	Net Risk Management Assets (Liabilities)
	(in millions)
Balance as of December 31, 2009	$ 62
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	5
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	63
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-
Purchases, Issuances and Settlements (c)	(25)
Transfers into Level 3 (d) (h)	18
Transfers out of Level 3 (e) (h)	(53)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	15
Balance as of December 31, 2010	$ 85

Year Ended December 31, 2009	Net Risk Management Assets (Liabilities)
	(in millions)
Balance as of December 31, 2008	$ 49
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(4)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	44
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-
Purchases, Issuances and Settlements (c)	(17)
Transfers in and/or out of Level 3 (f)	(25)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	15
Balance as of December 31, 2009	$ 62

Year Ended December 31, 2008	Net Risk Management Assets (Liabilities)	Other Temporary Investments	Investments in Debt Securities
		(in millions)	
Balance as of December 31, 2007	$ 49	$ -	$ -
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	-	-	-
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	12	-	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-	-	-
Purchases, Issuances and Settlements (c)	-	(118)	(17)
Transfers in and/or out of Level 3 (f)	(36)	118	17
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	24	-	-
Balance as of December 31, 2008	$ 49	$ -	$ -

(a) Included in revenues on our Consolidated Statements of Income.

(b) Represents the change in fair value between the beginning of the reporting period and the settlement of the risk management commodity contract.

(c) Represents the settlement of risk management commodity contracts for the reporting period.

(d) Represents existing assets or liabilities that were previously categorized as Level 2.

(e) Represents existing assets or liabilities that were previously categorized as Level 3.

(f) Represents existing assets or liabilities that were either previously categorized as a higher level for which the inputs to the model became unobservable or assets and liabilities that were previously classified as Level 3 for which the lowest significant input became observable during the period.

(g) Relates to the net gains (losses) of those contracts that are not reflected on our Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets.

(h) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.

12. INCOME TAXES

The details of our consolidated income taxes before discontinued operations and extraordinary loss as reported are as follows:

	Years Ended December 31, 2010	2009	2008
		(in millions)	
Federal:			
Current	$ (134)	$ (575)	$ 164
Deferred	760	1,171	456
Total Federal	626	596	620
State and Local:			
Current	(20)	(76)	(1)
Deferred	38	55	22
Total State and Local	18	(21)	21
International:			
Current	(1)	-	1
Deferred	-	-	-
Total International	(1)	-	1
Total Income Tax Expense Before Discontinued Operations and Extraordinary Loss	$ 643	$ 575	$ 642

The following is a reconciliation of our consolidated difference between the amount of federal income taxes computed by multiplying book income before income taxes by the federal statutory tax rate and the amount of income taxes reported.

	Years Ended December 31, 2010	2009	2008
		(in millions)	
Net Income	$ 1,218	$ 1,365	$ 1,388
Discontinued Operations, Net of Income Tax of $(10) million in 2008	-	-	(12)
Extraordinary Loss, Net of Income Tax of $3 million in 2009	-	5	-
Income Before Discontinued Operations and Extraordinary Loss	1,218	1,370	1,376
Income Tax Expense Before Discontinued Operations and Extraordinary Loss	643	575	642
Pretax Income	$ 1,861	$ 1,945	$ 2,018
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 651	$ 681	$ 706
Increase (Decrease) in Income Taxes resulting from the following items:			
Depreciation	47	31	23
Investment Tax Credits, Net	(16)	(19)	(19)
Energy Production Credits	(20)	(15)	(20)
State and Local Income Taxes	11	(14)	13
Removal Costs	(19)	(19)	(21)
AFUDC	(33)	(36)	(24)
Medicare Subsidy	12	(11)	(12)
Tax Reserve Adjustments	(16)	(6)	2
Other	26	(17)	(6)
Total Income Tax Expense Before Discontinued Operations and Extraordinary Loss	$ 643	$ 575	$ 642
Effective Income Tax Rate	34.6 %	29.6 %	31.8 %

The following table shows elements of the net deferred tax liability and significant temporary differences:

	December 31, 2010	December 31, 2009
	(in millions)	
Deferred Tax Assets	$ 2,519	$ 2,493
Deferred Tax Liabilities	(10,009)	(9,065)
Net Deferred Tax Liabilities	$ (7,490)	$ (6,572)
Property-Related Temporary Differences	$ (5,301)	$ (4,714)
Amounts Due from Customers for Future Federal Income Taxes	(250)	(229)
Deferred State Income Taxes	(622)	(523)
Securitized Transition Assets	(651)	(712)
Regulatory Assets	(867)	(862)
Accrued Pensions	218	335
Deferred Income Taxes on Other Comprehensive Loss	207	203
Accrued Nuclear Decommissioning	(395)	(356)
All Other, Net	171	286
Net Deferred Tax Liabilities	$ (7,490)	$ (6,572)

We, along with our subsidiaries, file a consolidated federal income tax return. The allocation of the AEP System's current consolidated federal income tax to the AEP System companies allocates the benefit of current tax losses to the AEP System companies giving rise to such losses in determining their current tax expense. The tax benefit of the Parent is allocated to our subsidiaries with taxable income. With the exception of the loss of the Parent, the method of allocation reflects a separate return result for each company in the consolidated group.

At December 31, 2010, we have federal general business credit carryforwards of $64 million. If these credits are not utilized, they will expire in the years 2028 through 2030.

We are no longer subject to U.S. federal examination for years before 2001. We have completed the exam for the years 2001 through 2006 and have issues that we are pursuing at the appeals level. The years 2007 and 2008 are currently under examination. Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for federal income taxes have been made for potential liabilities resulting from such matters. In addition, we accrue interest on these uncertain tax positions. We are not aware of any issues for open tax years that upon final resolution are expected to have a material adverse effect on net income.

We, along with our subsidiaries, file income tax returns in various state, local and foreign jurisdictions. These taxing authorities routinely examine our tax returns and we are currently under examination in several state and local jurisdictions. We believe that we have filed tax returns with positions that may be challenged by these tax authorities. Management believes that adequate provisions for income taxes have been made for potential liabilities resulting from such challenges and the ultimate resolution of these audits will not materially impact net income. With few exceptions, we are no longer subject to state, local or non-U.S. income tax examinations by tax authorities for years before 2000.

We sustained federal, state and local net income tax operating losses in 2009 driven primarily by bonus depreciation, a change in tax accounting method related to units of property and other book versus tax temporary differences. As a result, we accrued current federal, state and local income tax benefits in 2009. We realized the federal cash flow benefit in 2010 as there was sufficient capacity in prior periods to carry the net operating loss back. Most of our state and local jurisdictions do not provide for a net operating loss carry back. We anticipate future taxable income will be sufficient to realize the tax benefit. As such, we determined that a valuation allowance is unnecessary.

We recognize interest accruals related to uncertain tax positions in interest income or expense, as applicable, and penalties in Other Operation in accordance with the accounting guidance for "Income Taxes."

The following table shows amounts reported for interest expense, interest income and reversal of prior period interest expense:

	Years Ended December 31,		
	2010	2009	2008
		(in millions)	
Interest Expense	$ 8	$ 1	$ 10
Interest Income	11	5	21
Reversal of Prior Period Interest Expense	5	5	13

The following table shows balances for amounts accrued for the receipt of interest and the payment of interest and penalties:

	December 31,	
	2010	2009
	(in millions)	
Accrual for Receipt of Interest	$ 42	$ 30
Accrual for Payment of Interest and Penalties	21	18

The reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

	2010	2009	2008
		(in millions)	
Balance at January 1,	$ 237	$ 237	$ 222
Increase - Tax Positions Taken During a Prior Period	40	56	41
Decrease - Tax Positions Taken During a Prior Period	(43)	(65)	(45)
Increase - Tax Positions Taken During the Current Year	-	16	27
Decrease - Tax Positions Taken During the Current Year	(6)	-	(5)
Increase - Settlements with Taxing Authorities	-	1	3
Decrease - Settlements with Taxing Authorities	(2)	-	-
Decrease - Lapse of the Applicable Statute of Limitations	(7)	(8)	(6)
Balance at December 31,	$ 219	$ 237	$ 237

The total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate is $112 million, $137 million and $147 million for 2010, 2009 and 2008, respectively. We believe there will be no significant net increase or decrease in unrecognized tax benefits within 12 months of the reporting date.

Federal Tax Legislation

Under the Energy Tax Incentives Act of 2005, we filed applications with the United States Department of Energy and the IRS in 2008 for the West Virginia IGCC project and in July 2008 the IRS allocated the project $134 million in credits. In September 2008, we entered into a memorandum of understanding with the IRS concerning the requirements of claiming the credits. We had until July 2010 to meet certain minimum requirements under the agreement with the IRS or the credits would be forfeited. In July 2010, we forfeited the allocated tax credits.

The Economic Stimulus Act of 2008 provided enhanced expensing provisions for certain assets placed in service in 2008 and a 50% bonus depreciation provision similar to the one in effect in 2003 through 2004 for assets placed in service in 2008. The enacted provisions did not have a material impact on net income or financial condition, but provided a cash flow benefit of approximately $200 million in 2008.

The American Recovery and Reinvestment Tax Act of 2009 provided for several new grant programs and expanded tax credits and an extension of the 50% bonus depreciation provision enacted in the Economic Stimulus Act of 2008. The enacted provisions did not have a material impact on net income or financial condition. However, the bonus depreciation contributed to the 2009 federal net operating tax loss that resulted in a 2010 cash flow benefit of $419 million.

The Patient Protection and Affordable Care Act and the related Health Care and Education Reconciliation Act (Health Care Acts) were enacted in March 2010. The Health Care Acts amend tax rules so that the portion of employer health care costs that are reimbursed by the Medicare Part D prescription drug subsidy will no longer be deductible by the employer for federal income tax purposes effective for years beginning after December 31, 2012. Because of the loss of the future tax deduction, a reduction in the deferred tax asset related to the nondeductible OPEB liabilities accrued to date was recorded in March 2010. This reduction did not materially affect our cash flows or financial condition. For the year ended December 31, 2010, deferred tax assets decreased $56 million, partially offset by recording net tax regulatory assets of $35 million in our jurisdictions with regulated operations, resulting in a decrease in net income of $21 million.

The Small Business Jobs Act (the Act) was enacted in September 2010. Included in the Act was a one-year extension of the 50% bonus depreciation provision. The Tax Relief, Unemployment Insurance Reauthorization and the Job Creation Act of 2010 extended the life of research and development, employment and several energy tax credits originally scheduled to expire at the end of 2010. In addition, the Act extended the time for claiming bonus depreciation and increased the deduction to 100% for part of 2010 and 2011. The enacted provisions will not have a material impact on net income or financial condition but had a favorable impact on cash flows of $318 million in 2010.

State Tax Legislation

Under Ohio House Bill 66, in 2005, the Ohio companies established a regulatory liability for $57 million pending rate-making treatment in Ohio. For those companies in which state income taxes flow through for rate-making purposes, regulatory assets associated with the deferred state income tax liabilities were reduced by $22 million. In November 2006, the PUCO ordered that the $57 million be amortized to income as an offset to power supply contract losses incurred by CSPCo and OPCo for sales to Ormet. As of December 31, 2008, the $57 million regulatory liability was fully amortized.

The Ohio legislation also imposed a new commercial activity tax at a fully phased-in rate of 0.26% on all Ohio gross receipts. The tax was phased-in over a five-year period that began July 1, 2005 at 23% of the full 0.26% rate. As a result of this tax, expenses of approximately $13 million, $11 million and $9 million were recorded in 2010, 2009 and 2008, respectively, in Taxes Other Than Income Taxes.

Michigan Senate Bill 0094 (MBT Act), effective January 1, 2008, provided a comprehensive restructuring of Michigan's principal business tax. The law replaced the Michigan Single Business Tax. The MBT Act is composed of a new tax which is calculated based upon two components: (a) a business income tax (BIT) imposed at a rate of 4.95% and (b) a modified gross receipts tax (GRT) imposed at a rate of 0.80%, which will collectively be referred to as the BIT/GRT tax calculation. The law also includes significant credits for engaging in Michigan-based activity.

In March 2008, legislation was signed providing for, among other things, a reduction in the West Virginia corporate income tax rate from 8.75% to 8.5% beginning in 2009. The corporate income tax rate could also be reduced to 7.75% in 2012 and 7% in 2013 contingent upon the state government achieving certain minimum levels of shortfall reserve funds. We have evaluated the impact of the law change and the application of the law change will not materially impact our net income, cash flows or financial condition.

13. LEASES

Leases of property, plant and equipment are for periods up to 60 years and require payments of related property taxes, maintenance and operating costs. The majority of the leases have purchase or renewal options and will be renewed or replaced by other leases.

Lease rentals for both operating and capital leases are generally charged to Other Operation and Maintenance expense in accordance with rate-making treatment for regulated operations. Capital leases for nonregulated property are accounted for as if the assets were owned and financed. The components of rental costs are as follows:

Lease Rental Costs	Years Ended December 31, 2010	2009	2008
		(in millions)	
Net Lease Expense on Operating Leases	$ 343	$ 354	$ 368
Amortization of Capital Leases	97	83	97
Interest on Capital Leases	26	13	16
Total Lease Rental Costs	$ 466	$ 450	$ 481

The following table shows the property, plant and equipment under capital leases and related obligations recorded on our Consolidated Balance Sheets. Capital lease obligations are included in Other Current Liabilities and Deferred Credits and Other Noncurrent Liabilities on our Consolidated Balance Sheets.

Property, Plant and Equipment Under Capital Leases	December 31, 2010	2009
	(in millions)	
Generation	$ 97	$ 75
Distribution	-	-
Other Property, Plant and Equipment	482	379
Construction Work in Progress	-	-
Total Property, Plant and Equipment Under Capital Leases	579	454
Accumulated Amortization	108	139
Net Property, Plant and Equipment Under Capital Leases	$ 471	$ 315
Obligations Under Capital Leases		
Noncurrent Liability	$ 398	$ 244
Liability Due Within One Year	76	73
Total Obligations Under Capital Leases	$ 474	$ 317

Future minimum lease payments consisted of the following at December 31, 2010:

Future Minimum Lease Payments	Capital Leases	Noncancelable Operating Leases
	(in millions)	
2011	$ 100	$ 306
2012	88	286
2013	71	261
2014	59	241
2015	47	226
Later Years	286	1,349
Total Future Minimum Lease Payments	$ 651	$ 2,669
Less Estimated Interest Element	177	
Estimated Present Value of Future Minimum Lease Payments	$ 474	

Master Lease Agreements

We lease certain equipment under master lease agreements. In December 2010, we signed a new master lease agreement with GE Capital Commercial Inc. (GE) for approximately $137 million to replace existing operating and capital leases with GE. We refinanced approximately $60 million of capital leases and approximately $77 million in operating leases. These assets were included in existing master lease agreements that were to be terminated in 2011 since GE exercised the termination provision related to these leases in 2008. Approximately $16 million of currently leased assets were not included in the refinancing, but will be purchased or refinanced in 2011. In addition, approximately $40 million of operating leases that were previously under lease with GE are now recorded as capital leases after the refinancing. These obligations are included in the future minimum lease payments schedule earlier in this note.

For equipment under the GE master lease agreements, the lessor is guaranteed receipt of up to 84% of the unamortized balance of the equipment at the end of the lease term. If the fair value of the leased equipment is below the unamortized balance at the end of the lease term, we are committed to pay the difference between the fair value and the unamortized balance, with the total guarantee not to exceed 84% of the unamortized balance. For equipment under other master lease agreements, the lessor is guaranteed a residual value up to a stated percentage of either the unamortized balance or the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, we are committed to pay the difference between the actual fair value and the residual value guarantee. At December 31, 2010, the maximum potential loss for these lease agreements was approximately $14 million ($9 million, net of tax) assuming the fair value of the equipment is zero at the end of the lease term. Historically, at the end of the lease term the fair value has been in excess of the unamortized balance.

Rockport Lease

AEGCo and I&M entered into a sale-and-leaseback transaction in 1989 with Wilmington Trust Company (Owner Trustee), an unrelated, unconsolidated trustee for Rockport Plant Unit 2 (the Plant). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and securities in a private placement to certain institutional investors.

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the Plant and leases it equally to AEGCo and I&M. The lease is accounted for as an operating lease with the payment obligations included in the future minimum lease payments schedule earlier in this note. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the Plant. Neither AEGCo, I&M nor AEP has an ownership interest in the Owner Trustee and do not guarantee its debt. The future minimum lease payments for this sale-and-leaseback transaction as of December 31, 2010 are as follows:

Future Minimum Lease Payments	AEGCo	I&M
	(in millions)	
2011	$ 74	$ 74
2012	74	74
2013	74	74
2014	74	74
2015	74	74
Later Years	517	517
Total Future Minimum Lease Payments	$ 887	$ 887

Railcar Lease

In June 2003, AEP Transportation LLC (AEP Transportation), a subsidiary of AEP, entered into an agreement with BTM Capital Corporation, as lessor, to lease 875 coal-transporting aluminum railcars. The lease is accounted for as an operating lease. In January 2008, AEP Transportation assigned the remaining 848 railcars under the original lease agreement to I&M (390 railcars) and SWEPCo (458 railcars). The assignment is accounted for as operating leases for I&M and SWEPCo. The initial lease term was five years with three consecutive five-year renewal periods for a maximum lease term of twenty years. I&M and SWEPCo intend to renew these leases for the full lease term of twenty years via the renewal options. The future minimum lease obligations are $17 million for I&M and $19 million for SWEPCo for the remaining railcars as of December 31, 2010. These obligations are included in the future minimum lease payments schedule earlier in this note.

Under the lease agreement, the lessor is guaranteed that the sale proceeds under a return-and-sale option will equal at least a lessee obligation amount specified in the lease, which declines from approximately 84% under the current five year lease term to 77% at the end of the 20-year term of the projected fair value of the equipment. I&M and SWEPCo have assumed the guarantee under the return-and-sale option. I&M's maximum potential loss related to the guarantee is approximately $12 million ($8 million, net of tax) and SWEPCo's is approximately $13 million ($9 million, net of tax) assuming the fair value of the equipment is zero at the end of the current five-year lease term. However, we believe that the fair value would produce a sufficient sales price to avoid any loss.

Sabine Dragline Lease

During 2009, Sabine, an entity consolidated in accordance with the accounting guidance for "Variable Interest Entities," entered into capital lease arrangements with a nonaffiliated company to finance the purchase of two electric draglines to be used for Sabine's mining operations totaling $47 million. The amounts included in the lease represented the aggregate fair value of the existing equipment and a sale and leaseback transaction for additional dragline rebuild costs required to keep the dragline operational. In addition to the 2009 transactions, Sabine has one additional $53 million dragline completed in 2008 that was financed under a capital lease. These capital lease assets are included in Other Property, Plant and Equipment on our December 31, 2010 and 2009 Consolidated Balance Sheets. The short-term and long-term capital lease obligations are included in Other Current Liabilities and Deferred Credits and Other Noncurrent Liabilities on our December 31, 2010 and 2009 Consolidated Balance Sheets. The future payment obligations are included in our future minimum lease payments schedule earlier in this note.

I&M Nuclear Fuel Lease

In December 2007, I&M entered into a sale-and-leaseback transaction with Citicorp Leasing, Inc. (CLI), an unrelated, unconsolidated, wholly-owned subsidiary of Citibank, N.A. to lease nuclear fuel for I&M's Cook Plant. In December 2007, I&M sold a portion of its unamortized nuclear fuel inventory to CLI at cost for $85 million. The lease has a variable rate based on one month LIBOR and is accounted for as a capital lease with lease terms up to 60 months. The future payment obligations of $3 million are included in our future minimum lease payments schedule earlier in this note. The net capital lease asset is included in Other Property, Plant and Equipment and the short-term and long-term capital lease obligations are included in Other Current Liabilities and Deferred Credits and Other Noncurrent Liabilities, respectively, on our December 31, 2010 and 2009 Consolidated Balance Sheets. The future minimum lease payments for this sale-and-leaseback transaction as of December 31, 2010 are as follows, based on estimated fuel burn:

Future Minimum Lease Payments	Amount (in millions)
2011	$ 2
2012	1
Total Future Minimum Lease Payments	$ 3

14. FINANCING ACTIVITIES

AEP Common Stock

In April 2009, we issued 69 million shares of common stock at $24.50 per share for net proceeds of $1.64 billion, which were primarily used to repay cash drawn under our credit facilities in the second quarter of 2009.

Set forth below is a reconciliation of common stock share activity for the years ended December 31, 2010, 2009 and 2008:

Shares of AEP Common Stock	Issued	Held in Treasury
Balance, December 31, 2007	421,926,696	21,499,992
Issued	4,394,552	-
Treasury Stock Contributed to AEP Foundation	-	(1,250,000)
Balance, December 31, 2008	426,321,248	20,249,992
Issued	72,012,017	-
Treasury Stock Acquired	-	28,866
Balance, December 31, 2009	498,333,265	20,278,858
Issued	2,781,616	-
Treasury Stock Acquired	-	28,867
Balance, December 31, 2010	501,114,881	20,307,725

Preferred Stock

Information about the components of preferred stock of our subsidiaries is as follows:

	December 31, 2010			
	Call Price Per Share (a)	Shares Authorized (b)	Shares Outstanding (c)	Amount
Not Subject to Mandatory Redemption:				(in millions)
4.00% - 5.00%	$102-$110	1,525,903	600,641	$ 60

	December 31, 2009			
	Call Price Per Share (a)	Shares Authorized (b)	Shares Outstanding (c)	Amount
Not Subject to Mandatory Redemption:				(in millions)
4.00% - 5.00%	$102-$110	1,525,903	606,627	$ 61

(a) At the option of the subsidiary, the shares may be redeemed at the call price plus accrued dividends. The involuntary liquidation preference is $100 per share for all outstanding shares. If the subsidiary defaults on preferred stock dividend payments for a period of one year or longer, preferred stock holders are entitled, voting separately as one class, to elect the number of directors necessary to constitute a majority of the full board of directors of the subsidiary.

(b) As of December 31, 2010 and 2009, our subsidiaries had 14,494,227 and 14,488,294 shares of $100 par value preferred stock, respectively, 22,200,000 shares of $25 par value preferred stock and 7,822,535 and 7,822,482 shares of no par value preferred stock, respectively, that were authorized but unissued. Total shares authorized but unissued include shares not subject to mandatory redemption described in the above table.

(c) The number of preferred stock shares redeemed was 5,986 shares and 251 shares in 2010 and 2009, respectively. There were no preferred stock shares redeemed in 2008.

Long-term Debt

Type of Debt and Maturity	Weighted Average Interest Rate at December 31, 2010	Interest Rate Ranges at December 31, 2010	2009	Outstanding at December 31, 2010	2009
				(in millions)	
Senior Unsecured Notes					
2010-2015	4.99%	0.702%-6.375%	0.464%-6.375%	$ 3,318	$ 4,258
2016-2021	6.12%	5.00%-7.95%	5.00%-7.95%	4,020	4,020
2029-2040	6.41%	5.625%-8.13%	5.625%-8.13%	4,331	4,138
Pollution Control Bonds (a)					
2010-2015 (b)	2.95%	0.29%-6.25%	0.22%-7.125%	1,300	800
2017-2025	5.12%	4.45%-6.05%	0.23%-6.05%	443	595
2026-2042	5.19%	4.40%-6.30%	0.20%-6.30%	520	764
Notes Payable (c)					
2011-2026	5.44%	2.07%-8.03%	4.47%-8.03%	396	326
Securitization Bonds					
2010-2020	5.36%	4.98%-6.25%	4.98%-6.25%	1,847	1,995
Junior Subordinated Debentures (d)					
2063	8.75%	8.75%	8.75%	315	315
Spent Nuclear Fuel Obligation (e)				265	265
Other Long-term Debt					
2011-2059	1.72%	1.3125%-13.718%	1.25%-13.718%	91	88
Unamortized Discount (net)				(35)	(66)
Total Long-term Debt Outstanding				16,811	17,498
Less Portion Due Within One Year				1,309	1,741
Long-term Portion				$ 15,502	$ 15,757

(a) For certain series of pollution control bonds, interest rates are subject to periodic adjustment. Certain series may be purchased on demand at periodic interest adjustment dates. Letters of credit from banks, standby bond purchase agreements and insurance policies support certain series.

(b) Certain pollution control bonds are subject to mandatory redemption earlier than the maturity date. Consequently, these bonds have been classified for maturity and repayment purposes based on the mandatory redemption date.

(c) Notes payable represent outstanding promissory notes issued under term loan agreements and revolving credit agreements with a number of banks and other financial institutions. At expiration, all notes then issued and outstanding are due and payable. Interest rates are both fixed and variable. Variable rates generally relate to specified short-term interest rates.

(d) Debentures will mature on March 1, 2063, subject to extensions to no later than March 1, 2068, and are callable at par any time on or after March 1, 2013.

(e) Spent nuclear fuel obligation consists of a liability along with accrued interest for disposal of spent nuclear fuel (see "SNF Disposal" section of Note 6).

At December 31, 2010, $50 million of PSO's Senior Unsecured Notes, which are due within one year, are classified as long-term debt due to our intent and ability to refinance these notes on a long-term basis. In January 2011, PSO issued $250 million of 4.4% Senior Unsecured Notes due in 2021, demonstrating the ability to refinance these obligations on a long-term basis.

At December 31, 2009, approximately $472 million of variable-rate, tax-exempt bonds were outstanding. These bonds, which are short-term obligations, were classified as long-term due to our intent and ability to refinance each obligation on a long-term basis. At December 31, 2009, our $478 million credit facility had non-cancelable terms in excess of one year, demonstrating the ability to refinance these short-term obligations on a long-term basis.

Long-term debt outstanding at December 31, 2010 is payable as follows:

	2011	2012	2013	2014	2015	After 2015	Total
				(in millions)			
Principal Amount	$ 1,309	$ 815	$ 1,344	$ 941	$ 1,490	$ 10,947	$ 16,846
Unamortized Discount							(35)
Total Long-term Debt Outstanding							$ 16,811

In January 2011, TCC retired $92 million of its outstanding Securitization Bonds.

In February 2011, APCo issued $65 million of 2% Pollution Control Bonds due in 2041 with a 2012 mandatory put date.

As of December 31, 2010, trustees held, on our behalf, $303 million of our reacquired variable rate tax-exempt long-term debt.

Dividend Restrictions

Parent Restrictions

The holders of our common stock are entitled to receive the dividends declared by our Board of Directors provided funds are legally available for such dividends. Our income derives from our common stock equity in the earnings of our utility subsidiaries.

Pursuant to the leverage restrictions in our credit agreements, we must maintain a percentage of debt to total capitalization at a level that does not exceed 67.5%. The payment of cash dividends indirectly results in an increase in the percentage of debt to total capitalization of the company distributing the dividend. The method for calculating outstanding debt and capitalization is contractually defined in the credit agreements. None of AEP's retained earnings were restricted for the purpose of the payment of dividends.

We have issued $315 million of Junior Subordinated Debentures. The debentures will mature on March 1, 2063, subject to extensions to no later than March 1, 2068, and are callable at par any time on or after March 1, 2013. We have the option to defer interest payments on the debentures for one or more periods of up to 10 consecutive years per period. During any period in which we defer interest payments, we may not declare or pay any dividends or distributions on, or redeem, repurchase or acquire our common stock. We do not anticipate any deferral of those interest payments in the foreseeable future.

Utility Subsidiaries' Restrictions

Various financing arrangements, charter provisions and regulatory requirements may impose certain restrictions on the ability of our utility subsidiaries to transfer funds to us in the form of dividends. Specifically, most of our public utility subsidiaries have revolving credit agreements that contain a covenant that limits their debt to capitalization ratio to 67.5%. At December 31, 2010, the amount of restricted net assets of AEP's subsidiaries that may not be distributed to Parent in the form of a loan, advance or dividend was approximately $7 billion.

The Federal Power Act prohibits the utility subsidiaries from participating "in the making or paying of any dividends of such public utility from any funds properly included in capital account." The term "capital account" is not defined in the Federal Power Act or its regulations. Management understands "capital account" to mean the par value of the common stock multiplied by the number of shares outstanding. This restriction does not limit the ability of the utility subsidiaries to pay dividends out of retained earnings.

Lines of Credit and Short-term Debt

We use our commercial paper program to meet the short-term borrowing needs of our subsidiaries. The program is used to fund both a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds the majority of the nonutility subsidiaries. In addition, the program also funds, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either money pool for regulatory or operational reasons. As of December 31, 2010, we had credit facilities totaling $3 billion to support our commercial paper program (see "Credit Facilities" section below). The maximum amount of commercial paper outstanding during 2010 was $868 million and the weighted average interest rate of commercial paper outstanding during the year was 0.43%. Our outstanding short-term debt was as follows:

	December 31,			
	2010		2009	
Type of Debt	Outstanding Amount	Interest Rate (a)	Outstanding Amount	Interest Rate (a)
	(in millions)		(in millions)	
Securitized Debt for Receivables (b)	$ 690	0.31 %	$ -	-
Commercial Paper	650	0.52 %	119	0.26 %
Line of Credit – Sabine Mining Company (c)	6	2.15 %	7	2.06 %
Total Short-term Debt	$ 1,346		$ 126	

(a) Weighted average rate.
(b) Amount of securitized debt for receivables as accounted for under the "Transfers and Servicing" accounting guidance. See "ASU 2009-16 'Transfers and Servicing' " section of Note 2.
(c) Sabine Mining Company is a consolidated variable interest entity. This line of credit does not reduce available liquidity under AEP's credit facilities.

Credit Facilities

We have credit facilities totaling $3 billion to support our commercial paper program. The facilities are structured as two $1.5 billion credit facilities, of which $750 million may be issued under the credit facility that matures in April 2012 as letters of credit. In June 2010, we terminated one of the $1.5 billion facilities, which was scheduled to mature in March 2011, and replaced it with a new $1.5 billion credit facility which matures in June 2013 and allows for the issuance of up to $600 million as letters of credit. As of December 31, 2010, the maximum future payments for letters of credit issued under the two $1.5 billion credit facilities were $124 million.

In June 2010, we reduced a $627 million credit agreement that matures in April 2011 to $478 million. Under the facility, we may issue letters of credit. As of December 31, 2010, $477 million of letters of credit were issued by subsidiaries under this credit agreement to support variable rate Pollution Control Bonds.

Securitized Accounts Receivable – AEP Credit

AEP Credit has a receivables securitization agreement with bank conduits. Under the securitization agreement, AEP Credit receives financing from the bank conduits for the interest in the receivables AEP Credit acquires from affiliated utility subsidiaries. Prior to January 1, 2010, this transaction constituted a sale of receivables in accordance with the accounting guidance for "Transfers and Servicing," allowing the receivables to be removed from our Consolidated Balance Sheet. See "ASU 2009-16 'Transfers and Servicing' " section of Note 2 for discussion of the impact of new accounting guidance effective January 1, 2010 whereby such future transactions do not constitute a sale of receivables and will be accounted for as financings. AEP Credit continues to service the receivables. These securitized transactions allow AEP Credit to repay its outstanding debt obligations, continue to purchase our operating companies' receivables and accelerate AEP Credit's cash collections.

In July 2010, AEP Credit renewed its receivables securitization agreement. The agreement provides a commitment of $750 million from bank conduits to finance receivables from AEP Credit. A commitment of $375 million expires in July 2011 and the remaining commitment of $375 million expires in July 2013.

Accounts receivable information for AEP Credit is as follows:

	Years Ended December 31, 2010	2009	2008
	(dollars in millions)		
Proceeds from Sale of Accounts Receivable	$ N/A	$ 7,043	$ 7,717
Loss on Sale of Accounts Receivable	N/A	3	20
Average Variable Discount Rate on Sale of Accounts Receivable	N/A	0.57 %	3.19 %
Effective Interest Rates on Securitization of Accounts Receivable	0.31 %	N/A	N/A
Net Uncollectible Accounts Receivable Written Off	22	28	23

	December 31, 2010	2009
	(in millions)	
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	$ 923	$ 160
Deferred Revenue from Servicing Accounts Receivable	N/A	1
Retained Interest if 10% Adverse Change in Uncollectible Accounts	N/A	158
Retained Interest if 20% Adverse Change in Uncollectible Accounts	N/A	156
Total Principal Outstanding	690	656
Derecognized Accounts Receivable	N/A	631
Delinquent Securitized Accounts Receivable	50	29
Bad Debt Reserves Related to Securitization/Sale of Accounts Receivable	26	20
Unbilled Receivables Related to Securitization/Sale of Accounts Receivable	354	376

N/A Not Applicable

Customer accounts receivable retained and securitized for our operating companies are managed by AEP Credit. AEP Credit's delinquent customer accounts receivable represents accounts greater than 30 days past due.

15. STOCK-BASED COMPENSATION

As approved by shareholder vote, the Amended and Restated American Electric Power System Long-Term Incentive Plan (LTIP) authorizes the use of 20,000,000 shares of AEP common stock for various types of stock-based compensation awards, including stock options, to employees. A maximum of 10,000,000 shares may be used under this plan for full value share awards, which includes performance units, restricted shares and restricted stock units. The AEP Board of Directors and shareholders last approved the LTIP in 2010. The following sections provide further information regarding each type of stock-based compensation award granted by the Human Resources Committee of the Board of Directors (HR Committee).

Stock Options

We did not grant stock options in 2010, 2009 or 2008 but we do have outstanding stock options from grants in earlier periods that vested or were exercised in these years. The exercise price of all outstanding stock options equaled or exceeded the market price of AEP's common stock on the date of grant. All outstanding stock options were granted with a ten-year term and generally vested, subject to the participant's continued employment, in approximately equal 1/3 increments on January 1st of the year following the first, second and third anniversary of the grant date. We record compensation cost for stock options over the vesting period based on the fair value on the grant date. The LTIP does not specify a maximum contractual term for stock options.

The total fair value of stock options vested and the total intrinsic value of options exercised are as follows:

Stock Options	Years Ended December 31, 2010	2009	2008
		(in thousands)	
Fair Value of Stock Options Vested	$ -	$ 25	$ 25
Intrinsic Value of Options Exercised (a)	2,058	106	655

(a) Intrinsic value is calculated as market price at exercise dates less the option exercise price.

A summary of AEP stock option transactions during the years ended December 31, 2010, 2009 and 2008 is as follows:

	2010		2009		2008	
	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price
	(in thousands)		(in thousands)		(in thousands)	
Outstanding at January 1,	1,089	$ 32.78	1,128	$ 32.73	1,196	$ 32.69
Granted	-	N/A	-	N/A	-	N/A
Exercised/Converted	(448)	31.53	(21)	27.20	(68)	31.97
Forfeited/Expired	(90)	38.44	(18)	36.28	-	N/A
Outstanding at December 31,	551	32.88	1,089	32.78	1,128	32.73
Options Exercisable at December 31,	551	$ 32.88	1,089	$ 32.78	1,125	$ 32.72

The following table summarizes information about AEP stock options outstanding and exercisable at December 31, 2010:

2010 Range of Exercise Prices	Number of Options Outstanding and Exercisable	Weighted Average Remaining Life	Weighted Average Exercise Price	Aggregate Intrinsic Value
	(in thousands)	(in years)		(in thousands)
$27.06-27.95	266	2.20	$ 27.44	$ 2,273
$30.76-38.65	159	3.10	31.26	778
$44.10-49.00	126	0.50	46.40	-
Total	551	2.08	32.88	3,051

We include the proceeds received from exercised stock options in common stock and paid-in capital.

Performance Units

Our performance units have a value upon vesting equal to the market value of shares of AEP common stock. The number of performance units held is multiplied by the performance score to determine the actual number of performance units realized. The performance score is determined at the end of the performance period based on performance measures, which include both performance and market conditions, established for each grant at the beginning of the performance period by the HR Committee and can range from 0% to 200%. For the three-year performance and vesting period ending in 2009 and earlier performance periods, performance units are paid in cash or stock at the employee's election unless they are needed to satisfy a participant's stock ownership requirement. Starting with the three-year performance and vesting period ending in 2010 and later, performance units are paid in cash, unless they are needed to satisfy a participant's stock ownership requirement. In that case, the number of units needed to satisfy the participant's largest stock ownership requirement is mandatorily deferred as AEP Career Shares until after the end of the participant's AEP career. AEP Career Shares are a form of non-qualified deferred compensation that have a value equivalent to shares of AEP common stock and are paid in cash after the participant's termination of employment. Amounts equivalent to cash dividends on both performance units and

AEP Career Shares accrue as additional units. We recorded compensation cost for performance units over the three-year vesting period. The liability for both the performance units and AEP Career Shares, recorded in Employee Benefits and Pension Obligations on our Consolidated Balance Sheets, is adjusted for changes in value. The fair value of performance unit awards is based on the estimated performance score and the current 20-day average closing price of AEP common stock at the date of valuation.

The HR Committee awarded performance units and reinvested dividends on outstanding performance units and AEP Career Shares for the years ended December 31, 2010, 2009 and 2008 as follows:

	Years Ended December 31,		
Performance Units	**2010**	**2009**	**2008**
Awarded Units (in thousands)	736	1,179	1,384
Weighted Average Unit Fair Value at Grant Date	$ 35.43	$ 34.32	$ 30.11
Vesting Period (in years)	3	3	3

Performance Units and AEP Career Shares	Years Ended December 31,		
(Reinvested Dividends Portion)	**2010**	**2009**	**2008**
Awarded Units (in thousands)	211	224	149
Weighted Average Grant Date Fair Value	$ 34.70	$ 28.82	$ 37.21
Vesting Period (in years)	(a)	(a)	(a)

(a) The vesting period for the reinvested dividends on performance units is equal to the remaining life of the related performance units. Dividends on AEP Career Shares vest immediately upon grant.

Performance scores and final awards are determined and certified by the HR Committee in accordance with the pre-established performance measures within approximately a month after the end of the performance period. The HR Committee has discretion to reduce or eliminate the value of final awards, but may not increase them. The performance scores for all open performance periods are dependent on two equally-weighted performance measures: (a) three-year total shareholder return measured relative to the utility industry segment of the Standard and Poor's 500 Index and (b) three-year cumulative earnings per share measured relative to an AEP Board of Directors approved target. The value of each performance unit earned equals the average closing price of AEP common stock for the last 20 business days of the performance period.

The certified performance scores and units earned for the three-year period ended December 31, 2010, 2009 and 2008 were as follows:

	Years Ended December 31,		
	2010	**2009**	**2008**
Certified Performance Score	55.8 %	73.5 %	120.3 %
Performance Units Earned	489,013	593,175	1,088,302
Performance Units Manditorily Deferred as AEP Career Shares	33,501	26,635	42,214
Performance Units Voluntarily Deferred into the Incentive Compensation Deferral Program	6,583	27,855	66,415
Performance Units to be Paid in Cash	448,929	538,685	979,673

The cash payouts for the years ended December 31, 2010, 2009 and 2008 were as follows:

	Years Ended December 31,		
	2010	**2009**	**2008**
		(in thousands)	
Cash Payouts for Performance Units	$ 18,683	$ 30,034	$ 52,960
Cash Payouts for AEP Career Share Distributions	3,594	2,184	1,236

Restricted Shares and Restricted Stock Units

The independent members of the AEP Board of Directors granted 300,000 restricted shares to the then Chairman, President and CEO on January 2, 2004 upon the commencement of his AEP employment. Of these restricted shares, 50,000 vested on January 1, 2005, 50,000 vested on January 1, 2006, 66,666 vested on November 30, 2009 and 66,667 vested on November 30, 2010. The remaining 66,667 restricted shares will vest on November 30, 2011, subject to his continued AEP employment through that date. Compensation cost for restricted shares is measured at fair value on the grant date and recorded over the vesting period. Fair value is determined by multiplying the number of shares granted by the grant date market closing price, which was $30.76. The maximum term for these restricted shares is eight years and dividends on these restricted shares are paid in cash. AEP has not granted other restricted shares.

The HR Committee also grants restricted stock units (RSUs), which generally vest, subject to the participant's continued employment, over at least three years in approximately equal annual increments on the anniversaries of the grant date. For awards granted prior to 2009, additional RSUs granted as dividends vest on the last vesting date associated with that RSU grant. For awards granted in 2009 and later, additional RSUs granted as dividends vest on the same date as the underlying RSUs on which the dividends were awarded. Compensation cost is measured at fair value on the grant date and recorded over the vesting period. Fair value is determined by multiplying the number of units granted by the grant date market closing price. The maximum contractual term of outstanding RSUs is five years from the grant date.

In 2010, the HR Committee granted a total of 165,520 of RSUs to four CEO succession candidates to better ensure the retention of these candidates. These grants vest, subject to the candidates' continuous employment, in three approximately equal installments on August 3, 2013, August 3, 2014 and August 3, 2015.

The HR Committee awarded RSUs, including units awarded for dividends, for the years ended December 31, 2010, 2009 and 2008 as follows:

Restricted Stock Units	Years Ended December 31, 2010	2009	2008
Awarded Units (in thousands)	873	130	56
Weighted Average Grant Date Fair Value	$ 35.24	$ 29.29	$ 41.69

The total fair value and total intrinsic value of restricted shares and restricted stock units vested during the years ended December 31, 2010, 2009 and 2008 were as follows:

Restricted Shares and Restricted Stock Units	Years Ended December 31, 2010	2009	2008
	(in thousands)		
Fair Value of Restricted Shares and Restricted Stock Units Vested	$ 6,044	$ 6,573	$ 2,619
Intrinsic Value of Restricted Shares and Restricted Stock Units Vested (a)	5,993	5,445	2,534

(a) Intrinsic value is calculated as market price at exercise date.

A summary of the status of our nonvested restricted shares and RSUs as of December 31, 2010 and changes during the year ended December 31, 2010 are as follows:

Nonvested Restricted Shares and Restricted Stock Units	Shares/Units	Weighted Average Grant Date Fair Value
	(in thousands)	
Nonvested at January 1, 2010	366	$ 34.12
Granted	873	35.24
Vested	(173)	35.00
Forfeited	(40)	35.01
Nonvested at December 31, 2010	1,026	34.88

The total aggregate intrinsic value of nonvested restricted shares and RSUs as of December 31, 2010 was $37 million and the weighted average remaining contractual life was 3.09 years.

Other Stock-Based Plans

We also have a Stock Unit Accumulation Plan for Non-employee Directors providing each non-employee director with AEP stock units as a substantial portion of their quarterly compensation for their services as a director. Amounts equivalent to cash dividends on the stock units accrue as additional AEP stock units. The non-employee directors vest immediately upon award of the stock units. Stock units are paid in cash upon termination of board service or up to 10 years later if the participant so elects. Cash payments for stock units are calculated based on the average closing price of AEP common stock for the 20 trading days immediately preceding the payment date.

We recorded the compensation cost for stock units when the units are awarded and adjusted the liability for changes in value based on the current 20-day average closing price of AEP common stock at the date of valuation.

We had no material cash payouts for stock unit distributions for the years ended December 31, 2010, 2009 and 2008.

The Board of Directors awarded stock units, including units awarded for dividends, for the years ended December 31, 2010, 2009 and 2008 as follows:

Stock Unit Accumulation Plan for Non-Employee Directors	Years Ended December 31, 2010	2009	2008
Awarded Units (in thousands)	54	56	43
Weighted Average Grant Date Fair Value	$ 34.67	$ 29.56	$ 37.72

Share-based Compensation Plans

Compensation cost and the actual tax benefit realized for the tax deductions from compensation cost for share-based payment arrangements recognized in income and total compensation cost capitalized in relation to the cost of an asset for the years ended December 31, 2010, 2009 and 2008 were as follows:

Share-based Compensation Plans	Years Ended December 31, 2010	2009	2008
		(in thousands)	
Compensation Cost for Share-based Payment Arrangements (a)	$ 28,116	$ 31,165	$ (18,028)(b)
Actual Tax Benefit Realized	9,841	10,908	(6,310)(b)
Total Compensation Cost Capitalized	4,689	5,956	(5,026)(b)

(a) Compensation cost for share-based payment arrangements is included in Other Operation and Maintenance expenses on our Consolidated Statements of Income.
(b) In 2008, AEP's declining total shareholder return and lower stock price significantly reduced the accruals for performance units.

During the years ended December 31, 2010, 2009 and 2008, there were no significant modifications affecting any of our share-based payment arrangements.

As of December 31, 2010, there was $81 million of total unrecognized compensation cost related to unvested share-based compensation arrangements granted under the LTIP. Unrecognized compensation cost related to the performance units and AEP Career Shares will change as the fair value is adjusted each period and forfeitures for all award types are realized. Our unrecognized compensation cost will be recognized over a weighted-average period of 1.84 years.

Cash received from stock options exercised and actual tax benefit realized for the tax deductions from stock options exercised during the years ended December 31, 2010, 2009 and 2008 were as follows:

Share-based Compensation Plans	2010	2009	2008
	Years Ended December 31, (in thousands)		
Cash Received from Stock Options Exercised	$ 14,134	$ 567	$ 2,170
Actual Tax Benefit Realized for the Tax Deductions from Stock Options Exercised	706	35	219

Our practice is to use authorized but unissued shares to fulfill share commitments for stock option exercises and RSU vesting. Although we do not currently anticipate any changes to this practice, we could use treasury shares, shares acquired in the open market specifically for distribution under the LTIP or any combination thereof for this purpose. The number of new shares issued to fulfill vesting RSUs is generally reduced to offset AEP's tax withholding obligation.

16. PROPERTY, PLANT AND EQUIPMENT

Depreciation, Depletion and Amortization

We provide for depreciation of Property, Plant and Equipment, excluding coal-mining properties, on a straight-line basis over the estimated useful lives of property, generally using composite rates by functional class as follows:

2010	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges
	(in millions)			(in years)	(in millions)			(in years)
Generation	$ 14,147	$ 6,537	1.6 - 3.8 %	9 - 132	$ 10,205	$ 3,788	2.2 - 5.1 %	20 - 70
Transmission	8,576	2,481	1.4 - 3.0 %	25 - 87	-	-	- - - %	- - -
Distribution	14,208	3,607	2.4 - 3.9 %	11 - 75	-	-	- - - %	- - -
CWIP	2,615 (a)	47	N.M.	N.M.	143	9	N.M.	N.M.
Other	2,685	1,268	3.0 - 12.5 %	5 - 55	1,161	329	N.M.	N.M.
Total	$ 42,231	$ 13,940			$ 11,509	$ 4,126		

2009	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges
	(in millions)			(in years)	(in millions)			(in years)
Generation	$ 13,047	$ 6,460	1.6 - 3.8 %	9 - 132	$ 9,998	$ 3,479	1.9 - 3.3 %	20 - 70
Transmission	8,315	2,478	1.4 - 2.7 %	25 - 87	-	-	- - - %	- - -
Distribution	13,549	3,421	2.4 - 3.9 %	11 - 75	-	-	- - - %	- - -
CWIP	2,866 (a)	(19)	N.M.	N.M.	165	6	N.M.	N.M.
Other	2,616	1,130	4.2 - 12.8 %	5 - 55	1,128	385	N.M.	N.M.
Total	$ 40,393	$ 13,470			$ 11,291	$ 3,870		

2008	Regulated		Nonregulated	
Functional Class of Property	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges (in years)	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges (in years)
Generation	1.6 - 3.5 %	9 - 132	2.6 - 5.1 %	20 - 61
Transmission	1.4 - 2.7 %	25 - 87	- - - %	- - -
Distribution	2.4 - 3.9 %	11 - 75	- - - %	- - -
CWIP	N.M.	N.M.	N.M.	N.M.
Other	4.9 - 11.3 %	5 - 55	N.M.	N.M.

(a) Includes CWIP related to SWEPCo's Arkansas jurisdictional share of the Turk Plant.

N.M. Not Meaningful

We provide for depreciation, depletion and amortization of coal-mining assets over each asset's estimated useful life or the estimated life of each mine, whichever is shorter, using the straight-line method for mining structures and equipment. We use either the straight-line method or the units-of-production method to amortize mine development costs and deplete coal rights based on estimated recoverable tonnages. We include these costs in the cost of coal charged to fuel expense.

For rate-regulated operations, the composite depreciation rate generally includes a component for non-asset retirement obligation (non-ARO) removal costs, which is credited to Accumulated Depreciation and Amortization. Actual removal costs incurred are charged to Accumulated Depreciation and Amortization. Any excess of accrued non-ARO removal costs over actual removal costs incurred is reclassified from Accumulated Depreciation and Amortization and reflected as a regulatory liability. For nonregulated operations, non-ARO removal costs are expensed as incurred.

As of January 1, 2010, DHLC was deconsolidated and is now reported as an equity investment on our Consolidated Balance Sheet. Also, see the "ASU 2009-17 'Consolidations' " section of Note 2 for a discussion of the impact of new accounting guidance effective January 1, 2010.

Asset Retirement Obligations (ARO)

We record ARO in accordance with the accounting guidance for "Asset Retirement and Environmental Obligations" for our legal obligations for asbestos removal and for the retirement of certain ash disposal facilities, closure and monitoring of underground carbon storage facilities at Mountaineer Plant, wind farms and certain coal mining facilities, as well as for nuclear decommissioning of our Cook Plant. We have identified, but not recognized, ARO liabilities related to electric transmission and distribution assets as a result of certain easements on property on which we have assets. Generally, such easements are perpetual and require only the retirement and removal of our assets upon the cessation of the property's use. We do not estimate the retirement for such easements because we plan to use our facilities indefinitely. The retirement obligation would only be recognized if and when we abandon or cease the use of specific easements, which is not expected.

The following is a reconciliation of the 2010 and 2009 aggregate carrying amounts of ARO:

	Carrying Amount of ARO
	(in millions)
ARO at December 31, 2008	$ 1,158
Accretion Expense	73
Liabilities Incurred	47
Liabilities Settled	(24)
Revisions in Cash Flow Estimates	5
ARO at December 31, 2009 (a)	1,259
DHLC Deconsolidation (c)	(12)
Accretion Expense	75
Liabilities Incurred	32
Liabilities Settled	(20)
Revisions in Cash Flow Estimates	64
ARO at December 31, 2010 (b)	$ 1,398

(a) The current portion of our ARO, totaling $5 million, is included in Other Current Liabilities on our 2009 Consolidated Balance Sheet.

(b) The current portion of our ARO, totaling $4 million, is included in Other Current Liabilities on our 2010 Consolidated Balance Sheet.

(c) We adopted ASU 2009-17 effective January 1, 2010 and deconsolidated DHLC. As a result, we record only 50% of the final reclamation based on our share of the obligation instead of the previous 100%.

As of December 31, 2010 and 2009, our ARO liability was $1.4 billion and $1.3 billion, respectively, and included $930 million and $878 million, respectively, for nuclear decommissioning of the Cook Plant. As of December 31, 2010 and 2009, the fair value of assets that are legally restricted for purposes of settling the nuclear decommissioning liabilities totaled $1.2 billion and $1.1 billion, respectively, and are recorded in Spent Nuclear Fuel and Decommissioning Trusts on our Consolidated Balance Sheets.

Allowance for Funds Used During Construction (AFUDC) and Interest Capitalization

Our amounts of allowance for borrowed, including interest capitalized, and equity funds used during construction is summarized in the following table:

	Years Ended December 31,		
	2010	2009	2008
		(in millions)	
Allowance for Equity Funds Used During Construction	$ 77	$ 82	$ 45
Allowance for Borrowed Funds Used During Construction	53	67	75

Jointly-owned Electric Facilities

We have electric facilities that are jointly-owned with nonaffiliated companies. Using our own financing, we are obligated to pay a share of the costs of these jointly-owned facilities in the same proportion as our ownership interest. Our proportionate share of the operating costs associated with such facilities is included in our Consolidated Statements of Income and the investments and accumulated depreciation are reflected in our Consolidated Balance Sheets under Property, Plant and Equipment as follows:

			Company's Share at December 31, 2010		
	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in millions)	
W.C. Beckjord Generating Station (Unit No. 6) (a)	Coal	12.5 %	$ 19	$ -	$ 8
Conesville Generating Station (Unit No. 4) (b)	Coal	43.5 %	301	8	49
J.M. Stuart Generating Station (c)	Coal	26.0 %	507	23	163
Wm. H. Zimmer Generating Station (a)	Coal	25.4 %	771	10	366
Dolet Hills Generating Station (Unit No. 1) (f)	Lignite	40.2 %	258	5	192
Flint Creek Generating Station (Unit No. 1) (g)	Coal	50.0 %	116	7	62
Pirkey Generating Station (Unit No. 1) (g)	Lignite	85.9 %	503	10	358
Oklaunion Generating Station (Unit No. 1) (e)	Coal	70.3 %	395	4	201
Turk Generating Plant (h)	Coal	73.33 %	-	971	-
Transmission	N/A	(d)	63	3	48

			Company's Share at December 31, 2009		
	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in millions)	
W.C. Beckjord Generating Station (Unit No. 6) (a)	Coal	12.5 %	$ 19	$ -	$ 8
Conesville Generating Station (Unit No. 4) (b)	Coal	43.5 %	301	4	45
J.M. Stuart Generating Station (c)	Coal	26.0 %	499	15	153
Wm. H. Zimmer Generating Station (a)	Coal	25.4 %	767	4	355
Dolet Hills Generating Station (Unit No. 1) (f)	Lignite	40.2 %	255	4	188
Flint Creek Generating Station (Unit No. 1) (g)	Coal	50.0 %	116	5	61
Pirkey Generating Station (Unit No. 1) (g)	Lignite	85.9 %	497	8	350
Oklaunion Generating Station (Unit No. 1) (e)	Coal	70.3 %	390	6	195
Turk Generating Plant (h)	Coal	73.33 %	-	688	-
Transmission	N/A	(d)	70	1	47

(a) Operated by Duke Energy Corporation, a nonaffiliated company.
(b) Operated by CSPCo.
(c) Operated by The Dayton Power & Light Company, a nonaffiliated company.
(d) Varying percentages of ownership.
(e) Operated by PSO and also jointly-owned (54.7%) by TNC.
(f) Operated by CLECO, a nonaffiliated company.
(g) Operated by SWEPCo.
(h) Turk Generating Plant is currently under construction with a projected commercial operation date of 2012. SWEPCo jointly owns the plant with Arkansas Electric Cooperative Corporation (11.67%), East Texas Electric Cooperative (8.33%) and Oklahoma Municipal Power Authority (6.67%). Through December 2010, construction costs totaling $279 million have been billed to the other owners.
N/A Not Applicable

17. COST REDUCTION INITIATIVES

In April 2010, we began initiatives to decrease both labor and non-labor expenses with a goal of achieving significant reductions in operation and maintenance expenses. A total of 2,461 positions were eliminated across the AEP System as a result of process improvements, streamlined organizational designs and other efficiencies. Most of the affected employees terminated employment May 31, 2010. The severance program provides two weeks of base pay for every year of service along with other severance benefits.

We recorded a charge to expense in 2010 primarily related to the headcount reduction initiatives. We do not expect additional costs to be incurred related to this initiative.

	Total (in millions)
Incurred	$ 293
Settled	283
Adjustments	7
Remaining Balance at December 31, 2010	$ 17

These costs relate primarily to severance benefits. They are included primarily in Other Operation on the Consolidated Statements of Income and Other Current Liabilities on the Consolidated Balance Sheets. Approximately 99% of the expense was within the Utility Operations segment.

18. UNAUDITED QUARTERLY FINANCIAL INFORMATION

In our opinion, the unaudited quarterly information reflects all normal and recurring accruals and adjustments necessary for a fair presentation of our net income for interim periods. Quarterly results are not necessarily indicative of a full year's operations because of various factors. Our unaudited quarterly financial information is as follows:

	2010 Quarterly Periods Ended			
	March 31	June 30	September 30	December 31
	(in millions - except per share amounts)			
Total Revenues	$ 3,569	$ 3,360	$ 4,064	$ 3,434
Operating Income	758	394 (a)	1,025	486 (b)
Net Income	346	137 (a)	557	178 (b)
Amounts Attributable to AEP Common Shareholders:				
Net Income	344	136 (a)	555	176 (b)
Basic Earnings per Share Attributable to AEP Common Shareholders:				
Earnings per Share (c)	0.72	0.28	1.16	0.37
Diluted Earnings per Share Attributable to AEP Common Shareholders:				
Earnings per Share (c)	0.72	0.28	1.16	0.37

	2009 Quarterly Periods Ended			
	March 31	June 30	September 30	December 31
	(in millions - except per share amounts)			
Total Revenues	$ 3,458	$ 3,202	$ 3,547	$ 3,282
Operating Income	750	682	858	481
Income Before Extraordinary Loss	363	322	446	239
Extraordinary Loss, Net of Tax	-	(5)(d)	-	-
Net Income	363	317	446	239
Amounts Attributable to AEP Common Shareholders:				
Income Before Extraordinary Loss	360	321	443	238
Extraordinary Loss, Net of Tax	-	(5)(d)	-	-
Net Income	360	316	443	238
Basic Earnings (Loss) per Share Attributable to AEP Common Shareholders:				
Earnings per Share Before Extraordinary Loss (c)	0.89	0.68	0.93	0.49
Extraordinary Loss per Share	-	(0.01)	-	-
Earnings per Share (c)	0.89	0.67	0.93	0.49
Diluted Earnings (Loss) per Share Attributable to AEP Common Shareholders:				
Earnings per Share Before Extraordinary Loss (c)	0.89	0.68	0.93	0.49
Extraordinary Loss per Share	-	(0.01)	-	-
Earnings per Share (c)	0.89	0.67	0.93	0.49

(a) See Note 17 for discussion of expenses related to cost reduction initiatives recorded in the second quarter of 2010.
(b) Includes a $43 million refund provision for the 2009 Significantly Excessive Earnings Test in addition to various other provisions for certain regulatory and legal matters.
(c) Quarterly Earnings Per Share amounts are meant to be stand-alone calculations and are not always additive to full-year amount due to rounding.
(d) See "SWEPCo Texas Restructuring" in "Extraordinary Item" section of Note 2 for discussion of the extraordinary loss recorded in the second quarter of 2009.

CORPORATE AND SHAREHOLDER INFORMATION

Corporate Headquarters
1 Riverside Plaza
Columbus, OH 43215-2373
614-716-1000
AEP is incorporated in the State of New York.

Stock Exchange Listing – The Company's common stock is traded principally on the New York Stock Exchange under the ticker symbol AEP.

Internet Home Page – Information about AEP, including financial documents, Securities and Exchange Commission (SEC) filings, news releases, investor presentations, shareholder information and customer service information, is available on the Company's home page on the Internet at www.AEP.com/investors.

Inquiries Regarding Your Stock Holdings – Registered shareholders (shares that you own, in your name) should contact the Company's transfer agent, listed below, if you have questions about your account, address changes, stock transfer, lost certificates, direct deposits, dividend checks and other administrative matters. You should have your Social Security number or account number ready; the transfer agent will not speak to third parties about an account without the shareholder's approval or appropriate documents.

Transfer Agent & Registrar
Computershare Trust Company, N.A.
P.O. Box 43078
Providence, RI 02940-3078
For overnight deliveries:
Computershare Trust Company, N.A.
250 Royall Street
Canton, MA 02021-1011
Telephone Response Group: 1-800-328-6955
Internet address: www.computershare.com/investor
Hearing Impaired #: TDD: 1-800-952-9245

Beneficial Holders – (Stock held in a bank or brokerage account) – When you purchase stock and it is held for you by your broker, it is listed with the Company in the broker's name, and this is sometimes referred to as "street name" or a "beneficial owner." AEP does not know the identity of individual shareholders who hold their shares in this manner; we simply know that a broker holds a certain number of shares which may be for any number of customers. If you hold your stock in street name, you receive all dividend payments, annual reports and proxy materials through your broker. Therefore, questions about your account should be directed to your broker.

Dividend Reinvestment and Direct Stock Purchase Plan – A Dividend Reinvestment and Direct Stock Purchase Plan is available to all investors. It is an economical and convenient method of purchasing shares of AEP common stock, through initial cash investments, cash dividends and/or additional optional cash purchases. You may obtain the Plan prospectus and enrollment authorization form by contacting the transfer agent or by visiting www.AEP.com/investors/directstockpurchase.

Financial Community Inquiries – Institutional investors or securities analysts who have questions about the Company should direct inquiries to Bette Jo Rozsa, 614-716-2840, bjrozsa@AEP.com; Julie Sherwood, 614-716-2663, jasherwood@AEP.com; or Sara Macioch, 614-716-2835, semacioch@AEP.com. Individual shareholders should contact Kathleen Kozero, 614-716-2819, klkozero@AEP.com.

Number of Shareholders – As of December 31, 2010, there were approximately 91,000 registered shareholders and approximately 331,000 shareholders holding stock in street name through a bank or broker. There were 480,807,156 shares outstanding at December 31, 2010.

Form 10-K – Upon request, we will provide without charge a copy of our Form 10-K for the fiscal year ended December 31, 2010. A copy can be obtained via mail with a written request to AEP Investor Relations, by telephone at 1-800-237-2667 or electronically at klkozero@AEP.com.

Executive Leadership Team

Name	Age	Office
Michael G. Morris	64	Chairman of the Board and Chief Executive Officer
Nicholas K. Akins	50	President
Carl L. English	64	Vice Chairman
D. Michael Miller	63	Senior Vice President, General Counsel and Secretary
Robert P. Powers	56	President – AEP Utilities
Brian X. Tierney	43	Executive Vice President and Chief Financial Officer
Susan Tomasky	57	President – AEP Transmission

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AEPCoverageRatios.pdf

EX-12 5 ex12aep4q.htm COMPUTATION OF RATIOS

EXHIBIT 12

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIAIRIES
Computation of Consolidated Ratios of Earnings to Fixed Charges
(in millions except ratio data)

	Years Ended December 31,				
	2006	**2007**	**2008**	**2009**	**2010**
EARNINGS					
Income Before Income Tax Expense and Equity Earnings	$ 1,483	$ 1,663	$ 2,015	$ 1,938	$ 1,849
Fixed Charges (as below)	999	1,146	1,240	1,237	1,254
Preferred Security Dividend Requirements of Consolidated Subsidiaries	(4)	(4)	(4)	(4)	(4)
Total Earnings	$ 2,478	$ 2,805	$ 3,251	$ 3,171	$ 3,099
FIXED CHARGES					
Interest Expense	$ 729	$ 838	$ 957	$ 973	$ 999
Credit for Allowance for Borrowed Funds Used During Construction	82	79	75	67	53
Estimated Interest Element in Lease Rentals	184	225	204	193	198
Preferred Security Dividend Requirements of Consolidated Subsidiaries	4	4	4	4	4
Total Fixed Charges	$ 999	$ 1,146	$ 1,240	$ 1,237	$ 1,254
Ratio of Earnings to Fixed Charges	2.48	2.44	2.62	2.56	2.47

Analysts and Earnings Estimates - InvestorGui

Investing Basics

Analysts and Earnings Estimates

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Analyst Reports and Recommendations

Wall Street investment firms employ thousands of analysts whose job is to issue reports and recommendations on specific stocks. These analysts typically look at the company's fundamentals and then build financial models in order to project future trends, most notably future earnings . They then use these projections as a basis for issuing recommendations on whether or not they think the stock should be bought or sold. Analyst recommendations vary from one firm to another, but usually they resemble something along the lines of "strong buy," "buy," "hold," and "sell." Many investors take these recommendations quite seriously, and you'll notice that often times when an analyst changes his or her outlook on a stock the price will rise or fall immediately.

You should be careful when looking at analyst recommendations for several reasons. First of all, many analysts suffer from a conflict of interest between the firm that employs them and the company whose stock they track. Often times, an analyst will be responsible for issuing reports on a company that is a current or potential client of their employer (usually an investment bank). Since they know that their employer would like to keep the client's business, the analyst may be tempted to issue a rosier outlook for the stock than what it really deserves. You should also be careful regarding the actual recommendations themselves. There are very few "sell" recommendations issued; "buy" and "strong buy" are much more common, so much so that "buy" is sometimes interpreted to mean "not good enough for a strong buy, so not worth buying". Again, analysts do not want to offend any company that could be a potential client for their bank (which is every company), so many analysts put a positive spin on even the gloomiest of stocks.

Earnings Estimates and Earnings Whispers

In addition to issuing buy, hold, and sell recommendations, analysts also issue earnings estimates for companies. These earnings estimates are earnings per share numbers that the analyst believes a particular company will report in its next quarterly statement . Earnings estimates have become increasingly important on Wall Street in recent years, as companies that "beat" the estimates typically see their stock prices rise while those that do not usually watch them fall.

But earnings estimates and reports are subject to conflicts of interest. In an all-too-common practice, companies will guide analysts toward earnings numbers that are lower than what the company actually expects to report. As a result, companies often exceed expectations, which unsophisticated investors look at as a sign to buy. While the SEC is trying to reduce such abuses, you should still garner whatever earnings information you can from unbiased sources, such as the so-called "earnings whispers" or "whisper numbers". Earnings whispers are intended to help investors avoid being duped by misleading estimates. They are created using a variety of methods (such as polling individual investors or enlisting the help of independent, unbiased analysts), and are often more accurate than Wall Street's estimates.

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PRINCIPLES OF CORPORATE FINANCE

EIGHTH EDITION

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Milan Montreal New Delhi Santiago Seoul Singapore Sydney Taipei Toronto

Using the DCF Model to Set Gas and Electricity Prices

The prices charged by local electric and gas utilities are regulated by state commissions. The regulators try to keep consumer prices down but are supposed to allow the utilities to earn a fair rate of return. But what is fair? It is usually interpreted as r, the market capitalization rate for the firm's common stock. That is, the fair rate of return on equity for a public utility ought to be the rate offered by securities that have the same risk as the utility's common stock.[4]

Small variations in estimates of this return can have a substantial effect on the prices charged to the customers and on the firm's profits. So both utilities and regulators devote considerable resources to estimating r. They call r the **cost of equity capital.** Utilities are mature, stable companies which ought to offer tailor-made cases for application of the constant-growth DCF formula.[5]

Suppose you wished to estimate the cost of equity for Cascade Natural Gas, a local natural gas distribution company. Its stock was selling for \$22.35 per share at the start of 2004. Dividend payments for the next year were expected to be \$1.03 a share. Thus it was a simple matter to calculate the first half of the DCF formula:

$$\text{Dividend yield} = \frac{\text{DIV}_1}{P_0} = \frac{1.03}{22.35} = .046, \text{ or } 4.6\%$$

The hard part is estimating g, the expected rate of dividend growth. One option is to consult the views of security analysts who study the prospects for each company. Analysts are rarely prepared to stick their necks out by forecasting dividends to kingdom come, but they often forecast growth rates over the next five years, and these estimates may provide an indication of the expected long-run growth path. In the case of Cascade, analysts in 2004 were forecasting an annual growth of 5.7 percent.[6] This, together with the dividend yield, gave an estimate of the cost of equity capital:

$$r = \frac{\text{DIV}_1}{P_0} + g = .046 + .057 = .103, \text{ or } 10.3\%$$

An alternative approach to estimating long-run growth starts with the **payout ratio,** the ratio of dividends to earnings per share (EPS). For Cascade, this was forecasted at 66 percent. In other words, each year the company was plowing back into the business about 44 percent of earnings per share:

$$\text{Plowback ratio} = 1 - \text{payout ratio} = 1 - \frac{\text{DIV}}{\text{EPS}} = 1 - .66 = .44$$

[4]This is the accepted interpretation of the U.S. Supreme Court's directive in 1944 that "the returns to the equity owner [of a regulated business] should be commensurate with returns on investments in other enterprises having corresponding risks." *Federal Power Commission v. Hope Natural Gas Company,* 302 U.S. 591 at 603.

[5]There are many exceptions to this statement. For example, Pacific Gas & Electric (PG&E), which serves northern California, used to be a mature, stable company until the California energy crisis of 2000 sent wholesale electric prices sky-high. PG&E was not allowed to pass these price increases on to retail customers. The company lost more than \$3.5 billion in 2000 and was forced to declare bankruptcy in 2001. PG&E emerged from bankruptcy in 2004, but we may have to wait a while before it is again a suitable subject for the constant-growth DCF formula.

[6]In this calculation we're assuming that earnings and dividends are forecasted to grow forever at the same rate g. We'll show how to relax this assumption later in this chapter. The growth rate was based on the average earnings growth forecasted by Value Line and IBES. IBES compiles and averages forecasts made by security analysts. Value Line publishes its own analysts' forecasts.

Also, Cascade's ratio of earnings per share to book equity per share was about 12 percent. This is its **return on equity**, or **ROE:**

$$\text{Return on equity} = \text{ROE} = \frac{\text{EPS}}{\text{book equity per share}} = .12$$

If Cascade earns 12 percent of book equity and reinvests 44 percent of income, then book equity will increase by .44 × .12 = .053 or 5.3 percent. Earnings and dividends per share will also increase by 5.3 percent:

$$\text{Dividend growth rate} = g = \text{plowback ratio} \times \text{ROE} = .44 \times .12 = .053$$

That gives a second estimate of the market capitalization rate:

$$r = \frac{\text{DIV}_1}{P_0} + g = .046 + .053 = .099, \text{ or } 9.9\%$$

Although this estimate of the market capitalization rate for Cascade stock seems reasonable enough, there are obvious dangers in analyzing any single firm's stock with the constant-growth DCF formula. First, the underlying assumption of regular future growth is at best an approximation. Second, even if it is an acceptable approximation, errors inevitably creep into the estimate of g. Our two methods for calculating the cost of equity gave similar answers. That was a lucky chance; different methods can sometimes give very different answers.

Remember, Cascade's cost of equity is not its personal property. In well-functioning capital markets investors capitalize the dividends of all securities in Cascade's risk class at exactly the same rate. But any estimate of r for a single common stock is "noisy" and subject to error. Good practice does not put too much weight on single-company cost-of-equity estimates. It collects samples of similar companies, estimates r for each, and takes an average. The average gives a more reliable benchmark for decision making.

Table 4.2 shows DCF cost-of-equity estimates for Cascade and seven other gas distribution companies. These are all stable, mature companies for which the constant-growth DCF formula *ought* to work. Notice the variation in the cost-of-equity estimates. Some of the variation may reflect differences in the risk, but some is just noise. The average estimate is 10.2 percent.

Table 4.3 gives another example of DCF cost-of-equity estimates, this time for U.S. railroads in 2002.

Of course, you are not restricted to analyzing expected returns for particular industries; you can also use the DCF formula to estimate the expected return for the entire stock market. For example, Figure 4.2 shows the results of an exercise by Marston and Harris, which used analysts' forecasts of five-year earnings growth to produce DCF estimates of the average cost of equity for companies in the Standard & Poor's Index. You can see that as interest rates fell between 1982 and 1998, the estimated cost of equity fell from nearly 20 percent to just under 15 percent. The margin between the cost of equity and the rate of interest was much more stable and averaged 9.3 percent over the 17-year period.

Estimates of this kind are only as good as the long-term forecasts on which they are based. For example, several studies have observed that security analysts are subject to behavioral biases and their forecasts tend to be over-optimistic.[7] If so, such DCF estimates of the cost of equity should be regarded as upper estimates of the true figure.

[7]See, for example, A. Dugar and S. Nathan, "The Effect of Investment Banking Relationships on Financial Analysts' Earnings Investment Recommendations," *Contemporary Accounting Research* 12 (1995), pp. 131–160.

CAPM - (r_f)

DCF (b×r) = PR (PVGO)

5% - 8%

4.5 THE LINK BETWEEN STOCK PRICE AND EARNINGS PER SHARE

Investors often use the terms *growth stocks* and *income stocks*. They buy growth stocks primarily for the expectation of capital gains, and they are interested in the future growth of earnings rather than in next year's dividends. On the other hand, they buy income stocks primarily for the cash dividends. Let us see whether these distinctions make sense.

Imagine first the case of a company that does not grow at all. It does not plow back any earnings and simply produces a constant stream of dividends. Its stock would resemble the perpetual bond described in the last chapter. Remember that the return on a perpetuity is equal to the yearly cash flow divided by the present value. The expected return on our share would thus be equal to the yearly dividend divided by the share price (i.e., the dividend yield). Since all the earnings are paid out as dividends, the expected return is also equal to the earnings per share divided by the share price (i.e., the earnings–price ratio). For example, if the dividend is \$10 a share and the stock price is \$100, we have

$$\begin{aligned} \text{Expected return} &= \text{dividend yield} &&= \text{earnings–price ratio} \\ &= \frac{\text{DIV}_1}{P_0} &&= \frac{\text{EPS}_1}{P_0} \\ &= \frac{10.00}{100} &&= .10 \end{aligned}$$

The price equals

$$P_0 = \frac{\text{DIV}_1}{r} = \frac{\text{EPS}_1}{r} = \frac{10.00}{.10} = 100$$

The expected return for *growing* firms can *also* equal the earnings–price ratio. The key is whether earnings are reinvested to provide a return equal to the market capitalization rate. For example, suppose our monotonous company suddenly hears of an opportunity to invest \$10 a share next year. This would mean no dividend at $t = 1$. However, the company expects that in each subsequent year the project would earn \$1 per share, so that the dividend could be increased to \$11 a share.

Let us assume that this investment opportunity has about the same risk as the existing business. Then we can discount its cash flow at the 10 percent rate to find its net present value at year 1:

$$\text{Net present value per share at year 1} = -10 + \frac{1}{.10} = 0$$

Thus the investment opportunity will make no contribution to the company's value. Its prospective return is equal to the opportunity cost of capital.

What effect will the decision to undertake the project have on the company's share price? Clearly none. The reduction in value caused by the nil dividend in year 1 is exactly offset by the increase in value caused by the extra dividends in later years. Therefore, once again the market capitalization rate equals the earnings–price ratio:

$$r = \frac{\text{EPS}_1}{P_0} = \frac{10}{100} = .10$$

Project Rate of Return	Incremental Cash Flow, C	Project NPV in Year 1[a]	Project's Impact on Share Price in Year 0[b]	Share Price in Year 0, P_0	$\frac{EPS_1}{P_0}$	r
.05	$ .50	−$ 5.00	−$ 4.55	$ 95.45	.105	.10
.10	1.00	0	0	100.00	.10	.10
.15	1.50	+ 5.00	+ 4.55	104.55	.096	.10
.20	2.00	+ 10.00	+ 9.09	109.09	.092	.10

CAPM - (r+)

TABLE 4.6

Effect on stock price of investing an additional $10 in year 1 at different rates of return. Notice that the earnings–price ratio overestimates *r* when the project has negative NPV and underestimates it when the project has positive NPV.

[a]Project costs $10.00 ($EPS_1$). NPV = −10 + *C*/*r*, where *r* = .10.
[b]NPV is calculated at year 1. To find the impact on P_0, discount for one year at *r* = .10

Table 4.6 repeats our example for different assumptions about the cash flow generated by the new project. Note that the earnings–price ratio, measured in terms of EPS_1, next year's expected earnings, equals the market capitalization rate (*r*) *only* when the new project's NPV = 0. This is an extremely important point—managers frequently make poor financial decisions because they confuse earnings–price ratios with the market capitalization rate.

In general, we can think of stock price as the capitalized value of average earnings under a no-growth policy, plus **PVGO**, the **net present value of growth opportunities:**

EPR (PVGO)

$$P_0 = \frac{EPS_1}{r} + PVGO$$

The earnings–price ratio, therefore, equals

$$\frac{EPS}{P_0} = r\left(1 - \frac{PVGO}{P_0}\right)$$

It will underestimate *r* if PVGO is positive and overestimate it if PVGO is negative. The latter case is less likely, since firms are rarely *forced* to take projects with negative net present values.

Calculating the Present Value of Growth Opportunities for Fledgling Electronics

In our last example both dividends and earnings were expected to grow, but this growth made no net contribution to the stock price. The stock was in this sense an "income stock." Be careful not to equate firm performance with the growth in earnings per share. A company that reinvests earnings at below the market capitalization rate *r* may increase earnings but will certainly reduce the share value.

Now let us turn to that well-known *growth stock*, Fledgling Electronics. You may remember that Fledgling's market capitalization rate, *r*, is 15 percent. The company is expected to pay a dividend of $5 in the first year, and thereafter the dividend is predicted to increase indefinitely by 10 percent a year. We can, therefore, use the simplified constant-growth formula to work out Fledgling's price: 5%-8%

$$P_0 = \frac{DIV_1}{r - g} = \frac{5}{.15 - .10} = \$100$$

WE HAVE MANAGED to go through six chapters without directly addressing the problem of risk, but now the jig is up. We can no longer be satisfied with vague statements like "The opportunity cost of capital depends on the risk of the project." We need to know how risk is defined, what the links are between risk and the opportunity cost of capital, and how the financial manager can cope with risk in practical situations.

In this chapter we concentrate on the first of these issues and leave the other two to Chapters 8 and 9. We start by summarizing more than 100 years of evidence on rates of return in capital markets. Then we take a first look at investment risks and show how they can be reduced by portfolio diversification. We introduce you to beta, the standard risk measure for individual securities.

The themes of this chapter, then, are portfolio risk, security risk, and diversification. For the most part, we take the view of the individual investor. But at the end of the chapter we turn the problem around and ask whether diversification makes sense as a corporate objective.

7.1 OVER A CENTURY OF CAPITAL MARKET HISTORY IN ONE EASY LESSON

Financial analysts are blessed with an enormous quantity of data. There are comprehensive databases of the prices of U.S. stocks, bonds, options, commodities, as well as huge amounts of data for securities in other countries. We will focus on a study by Dimson, Marsh, and Staunton that measures the historical performance of three portfolios of U.S. securities:[1]

1. A portfolio of Treasury bills, that is, U.S. government debt securities maturing in less than one year.[2]
2. A portfolio of U.S. government bonds.
3. A portfolio of U.S. common stocks.

These investments offer different degrees of risk. Treasury bills are about as safe an investment as you can make. There is no risk of default, and their short maturity means that the prices of Treasury bills are relatively stable. In fact, an investor who wishes to lend money for, say, three months can achieve a perfectly certain payoff by purchasing a Treasury bill maturing in three months. However, the investor cannot lock in a *real* rate of return: There is still some uncertainty about inflation.

By switching to long-term government bonds, the investor acquires an asset whose price fluctuates as interest rates vary. (Bond prices fall when interest rates rise and rise when interest rates fall.) An investor who shifts from bonds to common stocks shares in all the ups and downs of the issuing companies.

Figure 7.1 shows how your money would have grown if you had invested $1 at the start of 1900 and reinvested all dividend or interest income in each of the three portfolios.[3] Figure 7.2 is identical except that it depicts the growth in the *real* value of the portfolio. We will focus here on nominal values.

[1]See E. Dimson, P. R. Marsh, and M. Staunton, *Triumph of the Optimists: 101 Years of Investment Returns* (Princeton, NJ: Princeton University Press, 2002).

[2]Treasury bills were not issued before 1919. Before that date the interest rate used is the commercial paper rate.

[3]Portfolio values are plotted on a log scale. If they were not, the ending values for the common stock portfolio would run off the top of the page.

5% - 8%

FIGURE 7.1

How an investment of $1 at the start of 1900 would have grown, assuming reinvestment of all dividend and interest payments.

Source: E. Dimson, P. R. Marsh, and M. Staunton, *Triumph of the Optimists: 101 Years of Investment Returns* (Princeton, NJ: Princeton University Press, 2002), with updates provided by the authors.

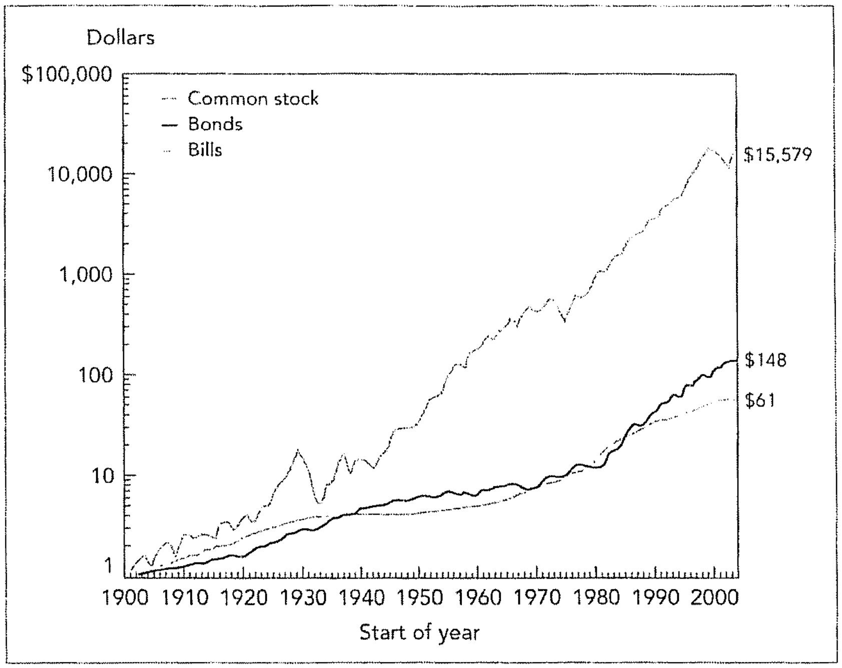
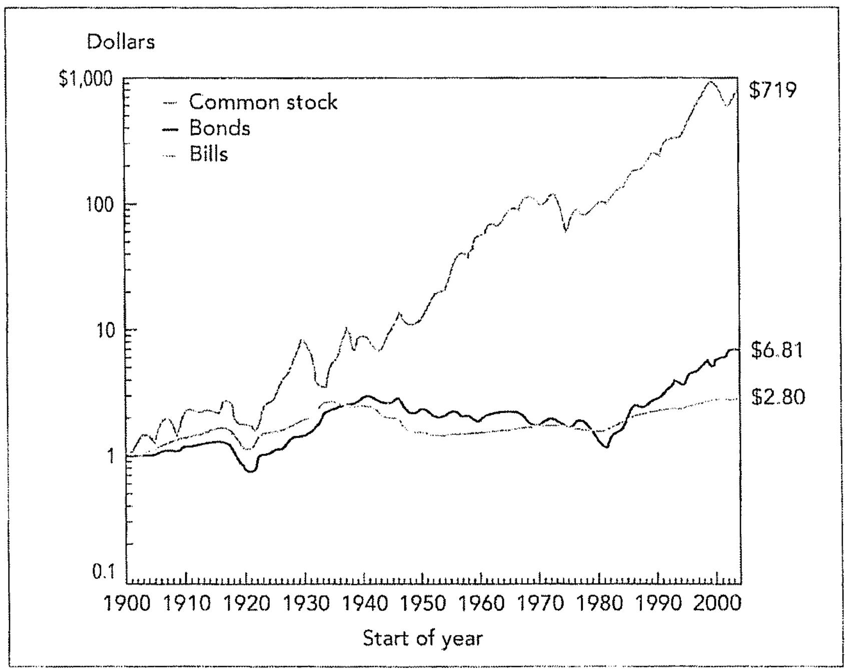


FIGURE 7.2

How an investment of $1 at the start of 1900 would have grown in real terms, assuming reinvestment of all dividend and interest payments. Compare this plot with Figure 7.1, and note how inflation has eroded the purchasing power of returns to investors.

Source: E. Dimson, P. R. Marsh, and M. Staunton, *Triumph of the Optimists: 101 Years of Investment Returns* (Princeton, NJ: Princeton University Press, 2002), with updates provided by the authors.



	Average Annual Rate of Return		Average Risk Premium (Extra Return versus Treasury Bills)
	Nominal	Real	
Treasury bills	4.1	1.1	0
Government bonds	5.2	2.3	1.2
Common stocks	11.7	8.5	7.6

TABLE 7.1

Average rates of return on U.S. Treasury bills, government bonds, and common stocks, 1900–2003 (figures in percent per year)

Source: E. Dimson, P. R. Marsh, and M. Staunton, *Triumph of the Optimists: 101 Years of Investment Returns*, (Princeton, NJ: Princeton University Press, 2002), with updates provided by the authors.

Investment performance coincides with our intuitive risk ranking. A dollar invested in the safest investment, Treasury bills, would have grown to $61 by the end of 2003, barely enough to keep up with inflation. An investment in long-term Treasury bonds would have produced $148. Common stocks were in a class by themselves. An investor who placed a dollar in the stocks of large U.S. firms would have received $15,579.

We can also calculate the rate of return from these portfolios for each year from 1900 to 2003. This rate of return reflects both cash receipts—dividends or interest—and the capital gains or losses realized during the year. Averages of the 104 annual rates of return for each portfolio are shown in Table 7.1.

Since 1900 Treasury bills have provided the lowest average return—4.1 percent per year in *nominal* terms and 1.1 percent in *real* terms. In other words, the average rate of inflation over this period was about 3 percent per year. Common stocks were again the winners. Stocks of major corporations provided an average nominal return of 11.7 percent. By taking on the risk of common stocks, investors earned a risk premium of 11.7 − 4.1 = 7.6 percent over the return on Treasury bills.

You may ask why we look back over such a long period to measure average rates of return. The reason is that annual rates of return for common stocks fluctuate so much that averages taken over short periods are meaningless. Our only hope of gaining insights from historical rates of return is to look at a very long period.[4]

[4]We cannot be sure that this period is truly representative and that the average is not distorted by a few unusually high or low returns. The reliability of an estimate of the average is usually measured by its *standard error*. For example, the standard error of our estimate of the average risk premium on common stocks is 2.0 percent. There is a 95 percent chance that the *true* average is within plus or minus 2 standard errors of the 7.6 percent estimate. In other words, if you said that the true average was between 3.6 and 11.6 percent, you would have a 95 percent chance of being right. *Technical note:* The standard error of the average is equal to the standard deviation divided by the square root of the number of observations. In our case the standard deviation is 20.1 percent, and therefore the standard error is $20.1 / \sqrt{104} = 2.0$.

5% - 8%

Arithmetic Averages and Compound Annual Returns

Notice that the average returns shown in Table 7.1 are arithmetic averages. In other words, we simply added the 104 annual returns and divided by 104. The arithmetic average is higher than the compound annual return over the period. The 104-year compound annual return for the S&P index was 9.7 percent.[5]

The proper uses of arithmetic and compound rates of return from past investments are often misunderstood. Therefore, we call a brief time-out for a clarifying example.

Suppose that the price of Big Oil's common stock is $100. There is an equal chance that at the end of the year the stock will be worth $90, $110, or $130. Therefore, the return could be −10 percent, +10 percent, or +30 percent (we assume that Big Oil does not pay a dividend). The *expected* return is $\frac{1}{3}(-10 + 10 + 30) = +10$ percent.

If we run the process in reverse and discount the expected cash flow by the expected rate of return, we obtain the value of Big Oil's stock:

$$PV = \frac{110}{1.10} = \$100$$

The expected return of 10 percent is therefore the correct rate at which to discount the expected cash flow from Big Oil's stock. It is also the opportunity cost of capital for investments that have the same degree of risk as Big Oil.

Now suppose that we observe the returns on Big Oil stock over a large number of years. If the odds are unchanged, the return will be −10 percent in a third of the years, +10 percent in a further third, and +30 percent in the remaining years. The arithmetic average of these yearly returns is

$$\frac{-10 + 10 + 30}{3} = +10\%$$

Thus the arithmetic average of the returns correctly measures the opportunity cost of capital for investments of similar risk to Big Oil stock.[6]

The average compound annual return[7] on Big Oil stock would be

$$(.9 \times 1.1 \times 1.3)^{1/3} - 1 = .088, \text{ or } 8.8\%,$$

which is *less* than the opportunity cost of capital. Investors would not be willing to invest in a project that offered an 8.8 percent expected return if they could get an

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[5] This was calculated from $(1 + r)^{104} = 15{,}579$, which implies $r = .097$. *Technical note:* For lognormally distributed returns the annual compound return is equal to the arithmetic average return minus half the variance. For example, the annual standard deviation of returns on the U.S. market was about .20, or 20 percent. Variance was therefore $.20^2$, or .04. The compound annual return is $.04/2 = .02$, or 2 percentage points less than the arithmetic average.

[6] You sometimes hear that the arithmetic average correctly measures the opportunity cost of capital for one-year cash flows, but not for more distant ones. Let us check. Suppose that you expect to receive a cash flow of $121 in year 2. We know that one-year hence investors will value that cash flow by discounting at 10 percent (the arithmetic average of possible returns). In other words, at the end of the year they will be willing to pay $PV_1 = 121/1.10 = \$110$ for the expected cash flow. But we already know how to value an asset that pays off $110 in year 1—just discount at the 10 percent opportunity cost of capital. Thus $PV_0 = PV_1/1.10 = 110/1.1 = \$100$. Our example demonstrates that the arithmetic average (10 percent in our example) provides a correct measure of the opportunity cost of capital regardless of the timing of the cash flow.

[7] The compound annual return is often referred to as the *geometric average* return.

expected return of 10 percent in the capital markets. The net present value of such a project would be

$$\text{NPV} = -100 + \frac{108.8}{1.1} = -1.1$$

Moral: If the cost of capital is estimated from historical returns or risk premiums, use arithmetic averages, not compound annual rates of return.[8]

CAPM - (+)

Using Historical Evidence to Evaluate Today's Cost of Capital

Suppose there is an investment project which you *know*—don't ask how—has the same risk as Standard and Poor's Composite Index. We will say that it has the same degree of risk as the *market portfolio*, although this is speaking somewhat loosely, because the index does not include all risky securities. What rate should you use to discount this project's forecasted cash flows?

Clearly you should use the currently expected rate of return on the market portfolio; that is the return investors would forgo by investing in the proposed project. Let us call this market return r_m. One way to estimate r_m is to assume that the future will be like the past and that today's investors expect to receive the same "normal" rates of return revealed by the averages shown in Table 7.1. In this case, you would set r_m at 11.7 percent, the average of past market returns.

Unfortunately, this is *not* the way to do it; r_m is not likely to be stable over time. Remember that it is the sum of the risk-free interest rate r_f and a premium for risk. We know that r_f varies. For example, in 1981 the interest rate on Treasury bills was about 15 percent. It is difficult to believe that investors in that year were content to hold common stocks offering an expected return of only 11.7 percent.

If you need to estimate the return that investors expect to receive, a more sensible procedure is to take the interest rate on Treasury bills and add 7.6 percent, the average *risk premium* shown in Table 7.1. For example, as we write this in early 2004 the interest rate on Treasury bills is about 1 percent. Adding on the average risk premium, therefore, gives

$$\begin{aligned} r_m(2004) &= r_f(2004) + \text{normal risk premium} \\ &= .01 + .076 = .086, \text{ or about } 8.5\% \end{aligned}$$

The crucial assumption here is that there is a normal, stable risk premium on the market portfolio, so that the expected *future* risk premium can be measured by the average past risk premium.

Even with over 100 years of data, we can't estimate the market risk premium exactly; nor can we be sure that investors today are demanding the same reward for risk that they were 50 or 100 years ago. All this leaves plenty of room for argument about what the risk premium *really* is.[9]

5% - 8%

[8] Our discussion above assumed that we *knew* that the returns of −10, +10, and +30 percent were equally likely. For an analysis of the effect of uncertainty about the expected return see I. A. Cooper, "Arithmetic Versus Geometric Mean Estimators: Setting Discount Rates for Capital Budgeting," *European Financial Management* 2 (July 1996), pp. 157–167.

[9] Some of the disagreements simply reflect the fact that the risk premium is sometimes defined in different ways. Some measure the average difference between stock returns and the returns (or yields) on long-term bonds. Others measure the difference between the compound rate of growth on stocks and the interest rate. As we explained above, this is not an appropriate measure of the cost of capital.

Many financial managers and economists believe that long-run historical returns are the best measure available. Others have a gut instinct that investors don't need such a large risk premium to persuade them to hold common stocks.[10] For example, two recent surveys of financial economists revealed that they expected a risk premium of between 5.5 percent and 7 percent,[11] while surveys of chief financial officers have suggested an average risk premium of 5.6 percent.[12]

If you believe that the expected market risk premium is less than the historical average, you probably also believe that history has been unexpectedly kind to investors in the United States and that their good luck is unlikely to be repeated. Here are two reasons that history *may* overstate the risk premium that investors demand today.

Reason 1 Since 1900 the United States has been among the world's most prosperous countries. Other economies have languished or been wracked by war or civil unrest. By focusing on equity returns in the United States, we may obtain a biased view of what investors expected. Perhaps the historical averages miss the possibility that the United States could have turned out to be one of these less-fortunate countries.[13]

Figure 7.3 sheds some light on this issue. It is taken from a comprehensive study by Dimson, Marsh, and Staunton of market returns in 16 countries and shows the average risk premium in each country between 1900 and 2003.[14] Although U.S. investors are far from top of the form in terms of risk premium that they have earned, they do appear to have been slightly luckier than the average investor in the 16 countries.

In Figure 7.3 Danish stocks come bottom of the league; the average risk premium in Denmark was only 4.3 percent. The clear winner was Italy with a premium of 10.7 percent. Some of these differences between countries may reflect differences in risk. For example, Italian stocks have been particularly variable and investors may have required a higher return to compensate. But remember how difficult it is to make precise estimates of what investors expected. You probably would not be too far out if you concluded that the *expected* risk premium was the same in each country.

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[10]There is some theory behind this instinct. The high risk premium earned in the market seems to imply that investors are extremely risk-averse. If that is true, investors ought to cut back their consumption when stock prices fall and wealth decreases. But the evidence suggests that when stock prices fall, investors spend at nearly the same rate. This is difficult to reconcile with high risk aversion and a high market risk premium. See R. Mehra and E. Prescott, "The Equity Premium: A Puzzle," *Journal of Monetary Economics* 15 (1985), pp. 145–161.

[11]The 7 percent figure comes from a survey conducted in 1998 and is reported in Ivo Welch, "Views of Financial Economists on the Equity Premium and on Professional Controversies," *Journal of Business* 73 (2000), pp. 501–537. The 5.5 percent figure comes from a follow-up survey in 2001, reported in Ivo Welch, "The Equity Premium Consensus Forecast Revisited," Cowles Foundation Discussion Paper No 1325, Yale School of Management, September 2001.

[12]These surveys were conducted between 2000 and 2003 and are reported in J. R. Graham and C. R. Harvey, "Expectations of Equity Risk Premia, Volatility and Asymmetry from a Corporate Finance Perspective" working paper, Duke University, Fuqua School of Business, July 2003. The CFOs forecasted a risk premium of 3.8 percent over 10-year Treasury bond yields, which is equivalent to 5.6 percent over the yield on 3-month Treasury bills.

[13]This possibility was suggested in P. Jorion and W. N. Goetzmann, "Global Stock Markets in the Twentieth Century," *Journal of Finance* 54 (June 1999), pp. 953–980.

[14]See E. Dimson, P. R. Marsh, and M. Staunton, *Triumph of the Optimists: 101 Years of Investment Returns* (Princeton, NJ: Princeton University Press, 2002).

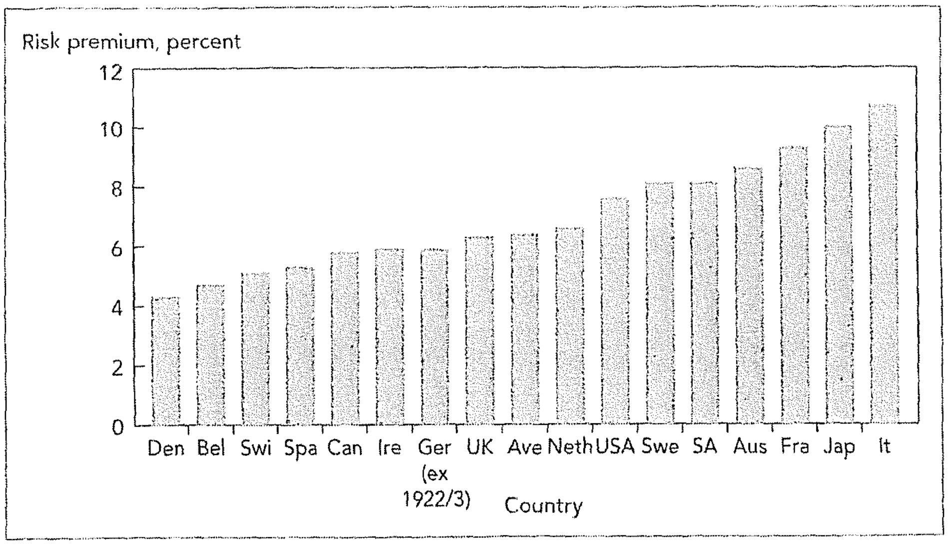

FIGURE 7.3

Average market risk premia (nominal return on stocks minus nominal return on bills), 1900–2003.

Source: E. Dimson, P. R. Marsh, and M. Staunton, *Triumph of the Optimists: 101 Years of Investment Returns* (Princeton, NJ: Princeton University Press, 2002), with updates provided by the authors.

Reason 2 Stock prices in the United States have for some years outpaced the growth in company dividends or earnings. For example, between 1950 and 2000 dividend yields in the United States fell from 7.2 percent to 1.2 percent. It seems unlikely that investors *expected* such a sharp decline in yields, in which case some part of the actual return during this period was *unexpected*.

Some believe that the low dividend yields at the end of the twentieth century reflected optimism that the new economy would lead to a golden age of prosperity and surging profits, but others attribute the low yields to a reduction in the market risk premium. Perhaps the growth in mutual funds has made it easier for individuals to diversify away part of their risk, or perhaps pension funds and other financial institutions have found that they also could reduce their risk by investing part of their funds overseas. If these investors can eliminate more of their risk than in the past, they may become content with a lower return.

To see how a rise in stock prices can stem from a fall in the risk premium, suppose that a stock is expected to pay a dividend next year of \$12 ($DIV_1 = 12$). The stock yields 3 percent and the dividend is expected to grow indefinitely by 7 percent a year ($g = .07$). Therefore the total return that investors expect is $r = 3 + 7 = 10$ percent. We can find the stock's value by plugging these numbers into the constant-growth formula that we introduced in Chapter 3:

$$PV = DIV_1/(r - g) = 12/(.10 - .07) = \$400$$

Imagine that investors now revise downward their required return to $r = 9$ percent. The dividend yield falls to 2 percent and the value of the stock rises to

$$PV = DIV_1/(r - g) = 12/(.09 - .07) = \$600$$

Thus a fall from 10 percent to 9 percent in the required return leads to a 50 percent rise in the stock price. If we include this price rise in our measures of past returns, we will be doubly wrong in our estimate of the risk premium. First, we will overestimate the return that investors required in the past. Second, we will fail to recognize that the return investors require in the future is lower than they needed in the past.

An Alternative Measure of the Risk Premium

We can check our measure of the risk premium by going back to the constant-growth model that we introduced in Chapter 4. One might expect that in the long run stock prices should keep pace with the growth in dividends. In this case an alternative measure of the expected market return is the average dividend yield plus the average long-term growth in dividends. Since 1900 dividend yields in the United States have averaged 4.7 percent and the annual growth in dividends has likewise been 4.7 percent. It seems that the *expected* market return over this period was 9.4 percent, or about 5.3 percent above the risk-free interest rate. This is 2.3 percent lower than the *realized* risk premium reported in Table 7.1.[15]

Fama and French have pointed out that much of this difference is due to the second half of the twentieth century, when dividend yields fell sharply.[16] Since 1950 dividend yields have averaged under 3.9 percent and the annual growth in dividends has been 5.4 percent.

This suggests that the expected market return during this period was 3.9 + 5.4 = 9.3 percent, or 4 percent above the average risk-free interest rate since 1950.

Out of this debate only one firm conclusion emerges: Do not trust anyone who claims to *know* what returns investors expect. History contains some clues, but ultimately we have to judge whether investors on average have received what they expected. Many financial economists rely on the evidence of history and therefore work with a risk premium of about 7.5 percent. The remainder generally use a somewhat lower figure. Brealey, Myers, and Allen have no official position on the issue, but we believe that a range of 5 to 8 percent is reasonable for the risk premium in the United States.

7.2 MEASURING PORTFOLIO RISK

You now have a couple of benchmarks. You know the discount rate for safe projects, and you have an estimate of the rate for average-risk projects. But you *don't* know yet how to estimate discount rates for assets that do not fit these simple

[15]Note, however, that depending on your forecasts of dividend growth, the constant-growth model can come up with estimates of the expected risk premium that are either higher or lower than the realized premium. In Chapter 4 we described a study by Marston and Harris, which used the constant-growth model to estimate the market risk premium. The study, which employed analysts' forecasts of long-term earnings growth, estimated that the expected risk-premium was 9.3 percent. However, we also noted in Chapter 4 that analysts tend to be unduly optimistic in their earnings forecasts.

[16]See E. F. Fama and K. R. French, "The Equity Premium," *Journal of Finance* 57 (April 2002), pp. 637–659. Fama and French quote even lower estimates of the risk premium. The difference largely reflects the fact that they define the risk premium as the difference between market returns and the commercial paper rate. Except for the years 1900–1918, the interest rates used in Table 7.1 are the rates on U.S. Treasury bills.

In May 2004, the risk-free interest rate was about 3.3 percent.[8] Suppose you decide to use a market risk premium of 8 percent. The resulting estimate for Union Pacific's cost of equity is about 7 percent:

$$\text{Cost of equity} = \text{Expected return} = r_f + \beta(r_m - r_f)$$
$$= 3.3 + .49 \times 8.0 = 7.2\%$$

It is always useful to get a check on such estimates. In this case, we can look back to Table 4.3, which presents cost-of-equity estimates based on the constant-growth DCF formula for Union Pacific and the railroad average. These DCF estimates are considerably higher, at 13.5 percent for Union Pacific and 12.6 percent for the industry. Are the DCF estimates too high, or the CAPM estimates too low? You could look to further checks, using DCF models with varying future growth rates[9] or perhaps arbitrage pricing theory. We showed in Section 8.4 how APT can be used to estimate expected returns.

9.3 SETTING DISCOUNT RATES WHEN YOU DON'T HAVE A BETA

Stock or industry betas provide a rough guide to the risk encountered in various lines of business. But an asset beta for the railroad business can take you only so far. Not all investments made in that industry are average-risk. And if you are the first to use railroad-track networks as interplanetary transmission antennas, you will not even have a useful industry beta to start with.

In some cases an asset is publicly traded. If so we can estimate risk from past prices. Suppose your company wants to assess the risk of investing in commercial real estate, for example, in a large office building for company headquarters. Here the company can turn to indexes of real estate prices and returns derived from sales and appraisals of commercial properties.[10]

What should a manager do if the asset has no such convenient price record? What if the proposed investment is not close enough to business as usual to justify using a company cost of capital?

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[8]The CAPM works period by period and calls for a short-term interest rate. But in May 2004, short-term interest rates were only about 1.5 percent, versus about 5.5 percent for long-term U.S. Treasury bonds. Could a discount rate based on a short-term interest rate of only 1.5 percent give the right discount rate for cash flows 10 or 20 years in the future?

Well, now that you mention it, probably not. But you cannot use the long-term rate either, because the market risk premium was defined and measured as the average difference between market returns and *short-term* Treasury bill rates (See Table 7.1). Here is our suggested procedure. Start with the long-term Treasury rate (5.5 percent in our example) and subtract the risk premium of Treasury bonds over bills (1.2 percent in Table 7.1). Thus 5.5 − 1.2 = 3.3 percent. This is a rough but reasonable estimate of the expected average future return on Treasury bills. We therefore use this rate in our example.

Sometimes the long-term Treasury rate is used without adjustment. If this shortcut is used, then the market risk premium must be restated as the average difference between market returns and *long-term* Treasury returns.

[9]The average growth rate in Table 4.3 is about 11 percent, a high rate to project in perpetuity. A multistage DCF model would generate cost-of-equity estimates closer to the CAPM estimate.

[10]See Chapter 23 in D. Geltner and N. G. Miller, *Commercial Real Estate Analysis and Investment* (Englewood Cliffs, NJ: Prentice Hall, 2001).

Chart I.xls

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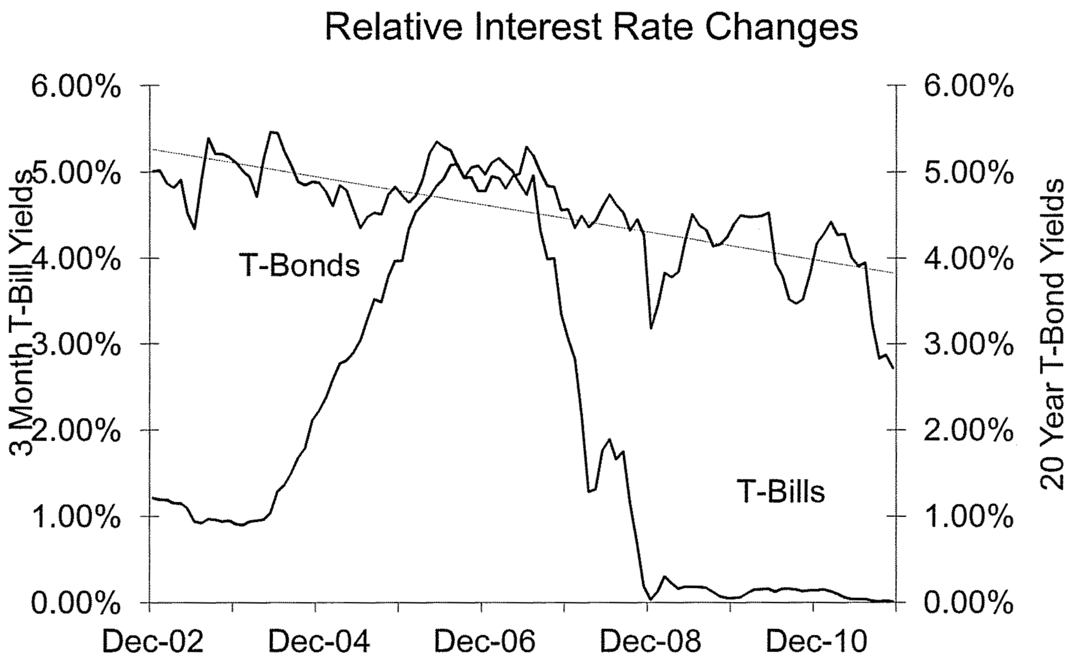
Relative Interest Rate Changes
3 Month T-Bill Yields
20 Year T-Bond Yields
6.00%
5.00%
4.00%
3.00%
2.00%
1.00%
0.00%
T-Bonds
T-Bills
Dec-02
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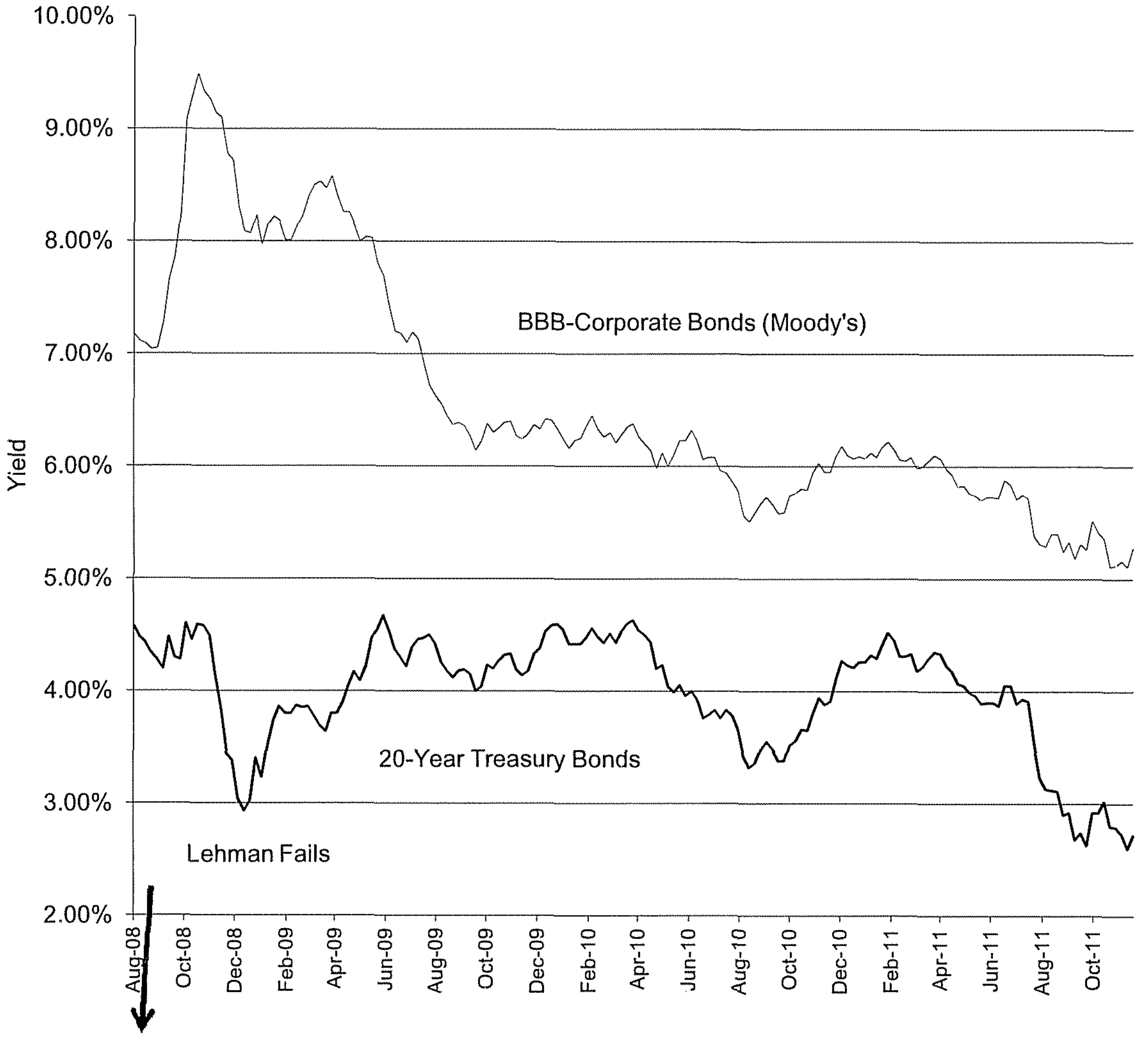
Dec-08
Dec-10

ChartII.xls


10.00%
9.00%
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Yield
BBB-Corporate Bonds (Moody's)
20-Year Treasury Bonds
Lehman Fails
Aug-08
Oct-08
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Feb-09
Apr-09
Jun-09
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GLOBAL EVIDENCE ON THE EQUITY RISK PREMIUM

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One of the most important contemporary issues in corporate finance is the magnitude of the equity risk premium. The risk premium is the incremental return that shareholders require from holding risky equities rather than risk-free securities. The risk premium drives future equity returns and is the key determinant of the cost of capital.

Today, investors have more cause than ever to ask what returns they can expect from equities, and what the future risk-reward tradeoff is likely to be. Companies also need to answer this question in order to understand what returns their shareholders require from projects of differing risk. Regulators, too, need to know the cost of capital in order to set 'fair' rates of return for regulated industries.

This paper sheds light on this important issue by addressing two key questions: What has the size of the equity risk premium been historically? And what can we expect for the future? To answer these questions, we need to look at long periods of capital market history, and extend our horizons beyond just the United States. In this paper, we therefore present evidence for sixteen different countries over the 102-year period from 1900–2001.

The need for a long-run perspective

The need for a long-run perspective, and the dangers of focusing just on recent stock market history, are easily demonstrated. Over the last decade of the twentieth century, US equity investors more than trebled their initial stake. In real terms, they achieved a total return (capital gain plus reinvested dividends) of 14.2 percent per annum. During the last five years of the1990s, US equities achieved high returns in every year, varying from a low of twenty-one percent in 1996 to a high of thirty-six percent in 1995. Many investors became convinced that high corporate growth rates could be extrapolated into the indefinite future. With steady growth rates, equity risk appeared lower. Simultaneously, there appeared to be a decline in the premium sought by investors to compensate for exposure to equity market risk. This drove stock prices onward and upward. Surveys suggested that, in consequence, many investors expected long-run stock market returns to continue at double-digit percentage rates of return.

Then the technology bubble burst. Growth projections had been unrealistic. High growth expectations were seen to be associated with high risk. Investors demanded a larger reward for equity market risk exposure. Stock prices fell in 2000 and then again in 2001, with no respite yet in 2002. With markets having fallen, investors started to project lower returns for the future.

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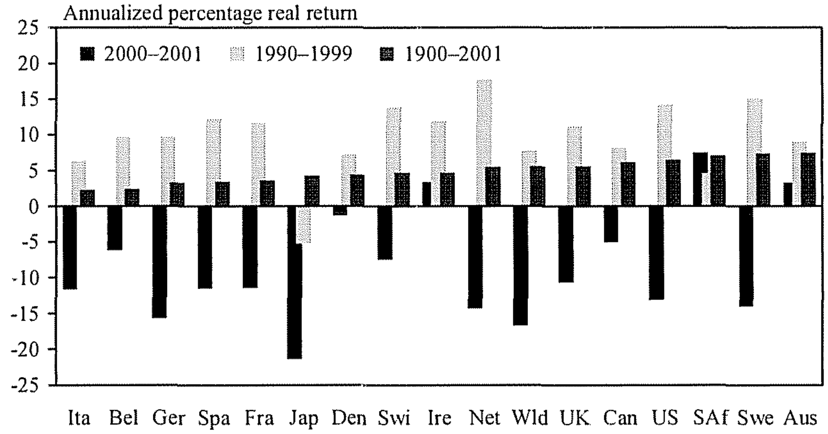
* This paper draws on, extends, and updates the research that underpinned our recent book, "*Triumph of the Optimists: 101 Years of Global Investment Returns*" (New Jersey: Princeton University Press, 2002). We are very grateful to ABN Amro for their extensive support and to our many international data contributors—too numerous to mention here, but all of whom are listed and cited in "Triumph" We are also grateful for the many helpful comments received from participants at numerous academic and practitioner seminars held around the world

FIGURE 1
SHORT-TERM AND LONG-RUN REAL RETURNS ON EQUITIES AROUND THE WORLD*



* The country names listed in abbreviated form along the horizontal axis are (from left to right) Italy, Belgium, Germany, Spain, France. Japan, Denmark, Switzerland, Ireland, The Netherlands. the world (the weighted average of the sixteen individual countries), The United Kingdom, Canada, The United States, South Africa, Sweden, and Australia

Yet it is dangerous to overreact to recent stock market performance. It would be wrong for investors to conclude that just because equities have delivered a low return since New Year 2000 that there has been either a substantial fall, or indeed rise, in the long-term expected equity premium.

Figure 1 shows how US equity returns compared with those in fifteen other countries and the world index. The black bars show annualized equity returns over 2000–01. In most countries, equities suffered negative returns, underperforming bonds everywhere except Ireland, and falling short of bill returns everywhere except Australia, Ireland, and South Africa. Estimating the expected risk premium from the performance of equities relative to bills or bonds over this period would clearly be nonsense. Investors cannot have required or expected a negative return for assuming risk. Instead, this was simply a very disappointing period for equities.

But while the opening years of the twenty-first century (fortunately) do not provide a basis for generalising about future returns, looking back at the previous decade only confuses the picture. Indeed, it would be equally misleading to estimate future risk premia from data for 1990–99. The light blue bars in Figure 1 show that over this period, equity returns (except in Japan and South Africa) were high. The 1990s was a golden age for stocks, and golden ages, by definition, recur infrequently.

To understand the risk premium—which is the principal objective of this paper—we need to examine periods that are much longer than one or two years, or even a decade. This is because stock markets are volatile, with much variation in year-to-year returns. In order to make inferences we thus need long time series that incorporate the bad times as well as the good. The dark blue bars in Figure 1 provide an insight into the perspective that longer periods of history can bring. These show real equity returns over the 102-year period from 1900–2001. Clearly, these 102-year returns are much less favourable than the returns during the 1990s, but equally, they contrast sharply with the disappointing returns over 2000–01.

Investors' judgements should thus be informed by the full extent of financial market history, and by looking not just at the United States, but at other countries as well.

Limitations of prior estimates of the risk premium

To be fair, financial economists do tend to measure the equity premium over quite long periods. Standard practice, however, draws heavily on the United States, with most textbooks citing only the US experience. By far the most widely cited US source prior to the end of the technology bubble was Ibbotson Associates[1], whose equity premium history starts in 1926. They estimated an annualized return on equities of 11.3 percent, and a risk-free return of 3.8 percent. This implied a geometric premium relative to bills of 7.3 percent (i.e., 1.113/1.038 = 1.073). References to other countries are few and far between, but a few textbooks also cite UK evidence. Before the publication of the research that underpins this paper, the most widely cited sources for the United Kingdom were the studies published by Barclays Capital and CSFB[2], which both started in 1919, and who published equity and risk-free returns of 12.2 and 5.5 percent, implying an annualized risk premium relative to bills of 6.4 percent.

In citing these estimates, financial economists are generally making the implicit assumption that provided the data are of sufficient quality, then the historical risk premium, measured over many decades, will provide an unbiased estimate of the future premium. Yet the twentieth century proved to be a period of remarkable growth in the US economy, and it seems probable that the outcome exceeded the expectations held in 1926 by US investors. Similar arguments apply to the United Kingdom, and the likely expectations of UK investors in 1919, but additionally, the UK evidence turned out to be based on a retrospectively constructed index whose composition, up to 1955, was tainted by survivor bias and narrow coverage.

In recent years, both practitioners and researchers have grown increasingly uneasy about these widely cited estimates, largely because they seem high. Apart from biases in index construction, the finger of suspicion has pointed mainly at success and survivorship bias. One influential study by Jorion and Goetzmann[3], for example, asserted, "the high equity premium obtained for US (and, by implication, UK) equities appears to be the exception rather than the rule" (parenthesis added). Recently, Zvi Bodie[4] argued that high US and UK premia are likely to be anomalous, and underlined the need for comparative international evidence. He pointed out that long-run studies are always of US or UK premia: "There were 36 active stock markets in 1900, so why do we only look at two? I can tell you—because many of the others don't have a 100-year history, for a variety of reasons." This paper helps fill this gap in our knowledge by providing a 102-year back-history of risk premia for sixteen of these markets.

NEW EVIDENCE

The new evidence on long-run risk premia presented in this paper is derived from a unique new database of long-run international returns. This comprises annual returns on stocks, bonds, bills, inflation, and currencies for sixteen countries from 1900–2001. The countries include the two main North American markets, namely, the United States and Canada, the United Kingdom, seven markets from what is now the Euro currency area, three other

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1 See Ibbotson Associates, 2000, *Stocks, Bonds, Bills and Inflation Yearbook*, Chicago, Ibbotson Associates

2 Barclays Capital, 1999, *Equity-Gilt Study*, London: Barclays Capital; and Credit Suisse First Boston, 1999, *The CSFB Equity-Gilt Study*, London: Credit Suisse First Boston

3 Jorion, P. and W. Goetzmann, "Global Stock Markets in the Twentieth Century", *Journal of Finance*, Vol 54, 1999, pp 953-80

4 Bodie, Z, "Longer time horizon 'does not reduce risk'" *Financial Times*, 26 January 2002

European markets, two Asia-Pacific markets, and one African market. Together, these countries made up 95 percent of the free float market capitalization of all world equities at start-2002, and we estimate that they comprised over 90 percent by value at the start of our period in 1900.

To compile this database, we assembled the best quality indices and returns data available for each national market from previous studies and other sources[5]. Where possible, we used data from peer-reviewed academic papers, although some studies were previously unpublished. To span the full period from 1900 onward, we typically linked more than one index series. For our own home market, the UK, we constructed our own indices, since hitherto there was no satisfactory record of long run returns. For the period since 1955, we used the London Business School Share Price Database to construct an index covering the entire UK equity market[6]. From 1900–55, we constructed an index of the performance of the largest 100 companies by a process of painstaking financial archaeology, collecting data from archives in the City of London. We also used archive data to construct indices for several other countries (e.g., Canada, Ireland, South Africa) for periods for which no data was previously available.

Unlike most previous long-term studies of global markets, all our investment returns include reinvested gross income as well as capital gains. Many early equity indices measure just capital gains, ignoring dividends, thereby introducing serious downward bias. Similarly, many early bond indices record just yields, ignoring price movements. Our database is thus more comprehensive and accurate than previous research, spans a longer period, and the common start-date of 1900 aids international comparisons. We can now set the US risk premia data alongside comparable 102-year risk premia series for fifteen other countries, and make international comparisons that help set the US experience in perspective.

Table 1 shows the historical equity risk premia for the sixteen countries over the 102-year period 1900–2001. We also display equity premia for the world, based on our world equity index. The latter comprises a sixteen-country, common-currency (here taken as US dollars) equity index in which each country is weighted by its start-year market capitalization or (in earlier years) its GDP[7]. The left-hand half of Table 1 shows equity premia measured relative to the return on treasury bills (or the nearest equivalent short-term instrument); the right-hand half shows premia calculated relative to the return on long-term government bonds. Since the world index is computed here from the perspective of a US (dollar) investor, the world equity risk premium relative to bills is calculated relative to the US risk free (i.e., treasury bill) rate. The world equity premium relative to bonds is calculated relative to a GDP-weighted, sixteen-country, common-currency (here taken as US dollars) world bond index.

In each half of the table we show three measures. These are, first, the geometric mean risk premium, namely, the annualized premium over the entire 102 years; second, the arithmetic mean of the 102 one-year premia; and third, the standard deviation of the 102 one-year premia. While the United States and the United Kingdom have indeed performed well, compared to other markets there is no indication that they are hugely out of line.

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5. Details of our data sources for all sixteen countries together with full citations are provided in Dimson, E, P R Marsh, and M Staunton, *Triumph of the Optimists: 101 Years of Global Investment Returns*, Princeton University Press, 2002

6 Dimson, E and P R Marsh, "UK Financial Market Returns 1955-2000", *Journal of Business*, Vol 74, pp 1–31

7. We use market capitalization weights from 1968 onward and GDP (gross domestic product) weights before then due to the lack of reliable comprehensive data on country capitalizations prior to that date

TABLE 1
EQUITY RISK PREMIA AROUND THE WORLD 1900–2001

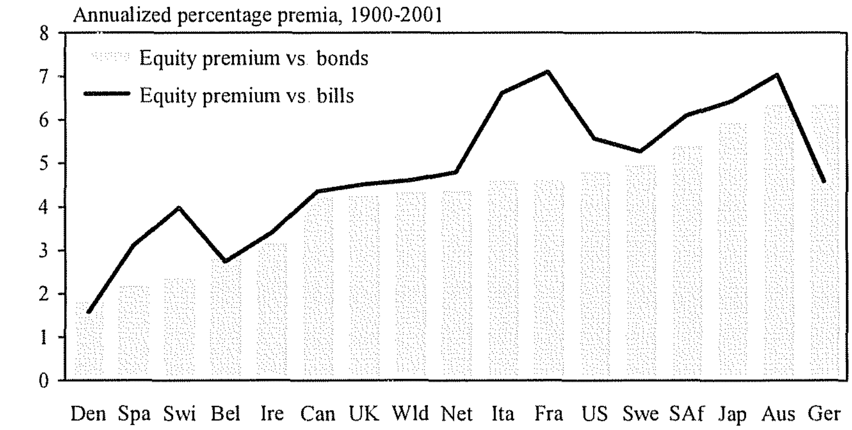
	Equity risk premia (percent per year)					
	Relative to bills			Relative to bonds		
Country	Geo-metric mean	Arith-metic mean	SD	Geo-metric mean	Arith-metic mean	SD
Australia	7.0	8.5	17.2	6.3	7.9	18.8
Belgium	2.7	5.0	23.5	2.8	4.7	20.7
Canada	4.4	5.7	16.7	4.2	5.7	17.9
Denmark	1.6	3.2	19.4	1.8	3.1	16.9
France	7.1	9.5	23.9	4.6	6.7	21.7
Germany*	4.6	10.0	35.3	6.3	9.6	28.5
Ireland	3.4	5.3	20.5	3.1	4.5	17.3
Italy	6.6	10.6	32.5	4.6	8.0	30.1
Japan	6.4	9.6	27.9	5.9	10.0	33.2
The Netherlands	4.8	6.8	22.3	4.4	6.4	21.5
South Africa	6.1	8.2	22.4	5.4	7.1	19.6
Spain	3.1	5.2	21.4	2.2	4.1	20.2
Sweden	5.3	7.4	21.9	4.9	7.1	22.1
Switzerland*	4.0	5.8	19.6	2.4	3.9	18.0
United Kingdom	4.5	6.2	19.9	4.2	5.5	16.7
United States	5.6	7.5	19.7	4.8	6.7	20.0
World	4.6	5.9	16.5	4.3	5.4	14.6

**Germany excludes 1922-23. Switzerland commences in 1911.*
Source: Dimson, Marsh, and Staunton, Triumph of the Optimists, Princeton University Press, 2002.

Over the entire 102-year period, the annualized equity risk premium, relative to bills, was 5.6 percent for the United States and 4.5 percent for the United Kingdom. Averaged across all sixteen countries, the risk premium relative to bills was 4.8 percent, while the risk premium on the world equity index was 4.6 percent. Relative to long bonds, the story is similar. The annualized US equity risk premium relative to bonds was 4.8 percent, and the corresponding figure for the United Kingdom was 4.2 percent. Across all sixteen countries, the risk premium relative to bonds averaged 4.3 percent, while for the world index it was also 4.3 percent.

The annualized equity risk premia are plotted in Figure 2. In this figure, countries are ranked by the equity premium relative to bonds, displayed as bars. The line-plot presents each country's risk premium relative to bills. It can be seen that the United States does indeed have a historical risk premium that is above the world average, but it is by no means the country with the largest recorded premium. The equity premium for the United Kingdom is closer to the worldwide average. While US and UK equities have performed well, both countries are towards the middle of the distribution of worldwide equity premia. Commentators have suggested that survivor bias may have given rise to equity premia for the United States and the United Kingdom that are unrepresentative. While legitimate, these concerns are somewhat overstated. Investors may not have been materially misled by a focus on the US and UK experiences. Rather, the critical factors are the period over which the risk premium is estimated, together with the quality of the index series.

FIGURE 2
WORLDWIDE ANNUALIZED EQUITY RISK PREMIA 1900–2001



Germany excludes 1922-23. Switzerland commences in 1911.
Source: Dimson, Marsh, and Staunton, Triumph of the Optimists, Princeton University Press, 2002.

Avoiding bias

There are noteworthy differences between the premia reported in this paper and those put forward, prior to publication of our research, by Ibbotson Associates in the United States, and by Barclays Capital and CSFB in the United Kingdom. Indeed, the premia estimated in this paper are around 1½ percent lower than those reported in these earlier studies. The differences arise from previous biases in index construction for the United Kingdom and, for both countries, from the choice of time frame, which in our case extends back to 1900[8]. We thus include the pre-1926 period for the United States (and pre-1919 for the United Kingdom) when returns were lower, partly due to events in the period leading up to, and including, World War I. Moreover, as noted above, prior perceptions about the risk premium have been dominated by the widely cited US estimates. Yet Table 1 and Figure 2 show that the premia for two-thirds of the other countries in our sample were lower than for the United States[9].

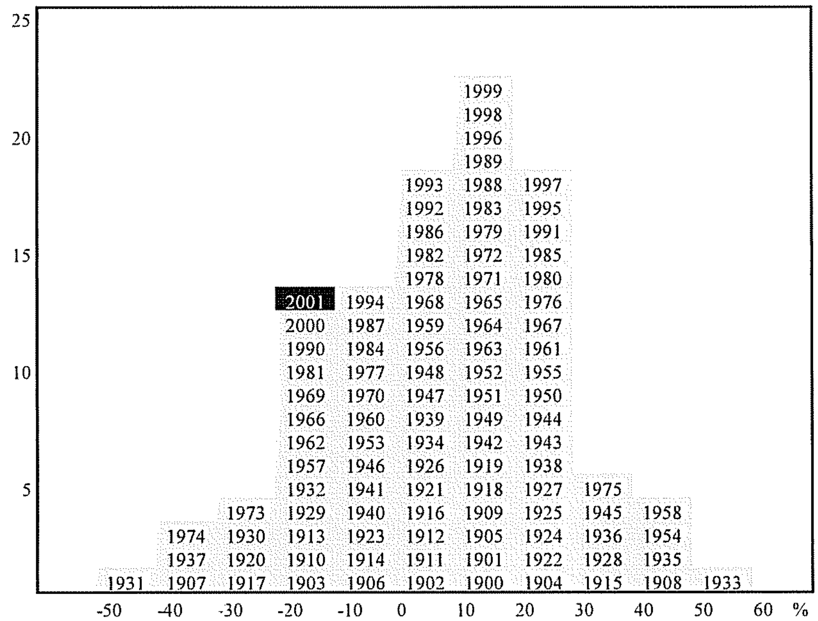
It is thus clear that the 102-year historical estimates of equity premia reported here are lower than was previously thought and other studies suggest. Even then, however, the historical record may overstate expectations. First, even if we have been successful in avoiding survivor bias within each index, we still focus on markets that survived, omitting countries such as Poland, Russia or China whose compound rate of return was –100 percent. Although these markets were relatively small in 1900[10], their omission probably leads to an overestimate of the

8 Interestingly, after publication of our research, Barclays Capital (but not CSFB) corrected their pre-1955 estimates of UK equity returns for bias and extended their index series back to 1900.

9 Table 1 shows that the annualized world equity risk premium relative to bills was 4.6 percent compared with 5.6 percent for the United States. Part of this difference, however, reflects the strength of the dollar over the period 1900–2001. The world risk premium is computed here from the world equity index expressed in dollars, in order to reflect the perspective of a US-based global investor. Since the currencies of most other countries depreciated against the dollar over the twentieth century, this lowers our estimate of the world equity risk premium relative to the (weighted) average of the local-currency based estimates for individual countries.

10 See Rajan, R and L Zingales, "The Great Reversals: The Politics of Financial Development in the 20th Century", Working paper No. 8178, Cambridge MA: National Bureau of Economic Research and Dimson, E, P R Marsh, and M Staunton, *Triumph of the Optimists: 101 Years of Global Investment Returns*, Princeton University Press, 2002.

FIGURE 3
HISTOGRAM OF US EQUITY RISK PREMIUM RELATIVE TO BILLS, 1900–2001



Source: Dimson, Marsh and Staunton, Triumph of the Optimists, Princeton University Press, 2002

worldwide risk premium.[11] Second, our premia are estimated relative to bills and bonds, which in a number of countries gave markedly negative real returns. Since these "risk-free" returns likely fell below investors' expectations, the corresponding equity premia are probably overstated.[12]

Although there is room for debate, we do not consider market survivorship to be the most important source of bias when inferring expected premia from the historical record. There are cogent arguments for suggesting that investors expected a lower premium than they actually received. However, this is more to do with a failure to fully anticipate improvements in business and investment conditions during the second half of the last century, an issue that we will return to below.

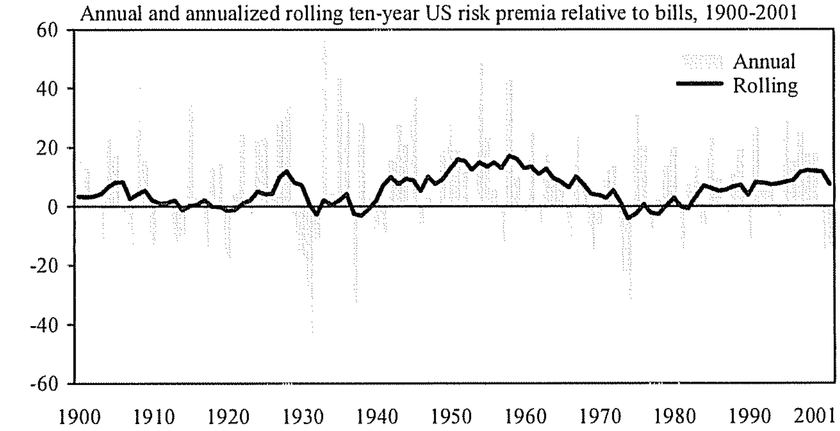
VARIATION IN RISK PREMIA OVER TIME

The historical equity premia shown in Figure 2 are the geometric means of 102 separate one-year premia that vary a great deal. In Figure 3 we show the year-by-year premia on US equities relative to bills. The lowest excess return was –45 percent in 1931, when equities returned –44 percent and treasury bills 1.1 percent; the highest was 57 percent in 1933, when equities gave 57.6 percent and bills 0.3 percent. Figure 3 shows that, for the United States,

11 We say omitting non-surviving markets "probably" gives rise to overestimated risk premia because of the possibility that some defaulting countries have returns of –100 percent on bonds, while equities retain some residual value. For such countries, the ex post equity premium would be positive.

12 We again say low risk-free rates probably give rise to overstated risk premia because equity returns would presumably have been higher if economic conditions had not given rise to markedly negative real fixed-income returns. If economic conditions had been better, it is possible that the equity premium would then have been larger.

FIGURE 4
ROLLING AND ANNUAL TEN-YEAR US PREMIA RELATIVE TO BILLS, 1900–2001



Source: Dimson, Marsh and Staunton, Triumph of the Optimists, Princeton University Press, 2002

the distribution of annual excess returns is roughly symmetrical with a mean of 7.5 percent and a standard deviation of 19.7 percent. On average, therefore, US investors received a positive, and quite large, reward for exposure to equity market risk.

Because the range of excess returns encountered on a year-to-year basis is very broad, it can be misleading to label them "risk premia." As already noted, investors cannot have expected, let alone required, a negative risk premium from investing in equities, otherwise they would simply have avoided them. All the negative and many of the very low premia plotted in the histogram must therefore reflect nasty surprises. Equally, investors could not have required premia as high as 57 percent in 1933. Such numbers are implausible as a required reward for risk, and the high realizations must therefore reflect pleasant surprises. To avoid confusion, many writers choose not to refer to annual excess returns as "risk premia". They simply clarify that excess returns are ex post returns in excess of the risk free interest rate.

As we noted above, because one-year excess returns are so variable, we need to examine much longer periods, in the hope that good and bad luck might then cancel out. A common choice of time frame is a decade. In Figure 4, we show the US equity risk premium, measured over a sequence of rolling ten-year periods, superimposed on the annual returns since 1900.

Even over ten-year periods, the historical risk premium was sometimes negative, most recently in the 1970s and early 1980s. Again, since investors cannot have required a negative reward for risk, these must reflect unpleasant surprises. Figure 4 also reveals several cases of double-digit ten-year premia. These must have been pleasant surprises, as they are too high to reflect prior expectations. Clearly, a decade is still too short a period for good and bad luck to cancel out, and for drawing inferences about investors' expectations. Over a decade, like a single year, all we are plotting is the excess return that was realised over a period in the past.

Imprecise estimates

Prior to our research, studies for countries other than the United States and United Kingdom used the longest stock return series available, typically covering an interval of up to half a century. Sadly, even such a long research period does not yield an answer that is invariant to the choice of period. Taking the United Kingdom as an illustration, the arithmetic mean annual excess return for the first half of the twentieth century was only 3.1 percent, as compared to 9.2 percent from 1950 to date.

Even with a full century of data, market fluctuations have an impact. All we can state with confidence is what the excess return was in the past. This is why some writers restrict the term "risk premium" to denote the expected reward from equity investment. To avoid confusion, we make it clear when we are looking to the future by referring to the expected or "prospective" risk premium. When we measure the excess return over a period in the past we generally refer to this as the "historical" risk premium.

With 102 years of data, the potential inaccuracy in historical risk premia is high. The standard error measures this inaccuracy. It is approximately equal to one-tenth of the annual standard deviation of returns reported in Table 1. The standard error for the United States is 1.9 percent, and the range runs from 1.7 percent (Australia and Canada) to 3.5 percent (Germany). This means that while the US arithmetic mean premium (relative to bills) has a best estimate of 7.5 percent, we can be only two-thirds confident that the true mean lies within one standard error of this, namely within the range 7.5 ± 1.9 percent, or 5.6 to 9.4 percent. Similarly, there is a nineteen-out-of-twenty probability that the true mean lies within two standard errors, namely 7.5 ± 3.8 percent, or 3.7 to 11.3 percent. These high standard errors are why the longest possible series of stock market data should in general be used for estimating risk premia.

FROM THE PAST TO THE FUTURE

To estimate the equity risk premium to use in discounting future cash flows, we need the expected future risk premium, i.e., the arithmetic mean of the possible premia that may occur. Suppose the returns that may happen in the future are drawn from the same distribution as those that occurred in the past. If so, the expected risk premium is the arithmetic mean (or simple average) of the one-year historical premia. Whenever there is some variability in annual premia, the arithmetic mean will always exceed the geometric mean (or annualized) risk premium.[13]

In Figure 5, the full height of the bars shows the historical arithmetic mean premium relative to bills for each country. The US equity premium is 7.5 percent, while the world equity risk premium is 5.9 percent. The arithmetic mean premia are noticeably higher than the geometric mean premia shown by the light blue portion of each bar. They are at their largest (in both absolute terms and relative to the geometric mean) for the countries that experienced the greatest volatility of returns over the last century (see Table 1).

In looking to the future, let us assume for the moment that investors in each country expect the same annualized (geometric mean) risk premium as they have received in the past. The bar and line plots in Figure 5 can then be interpreted as forecasts of the prospective arithmetic risk premia under alternative assumptions about future volatility. If there were no volatility in future annual returns, the expected arithmetic risk premia would be equal to their (historical)

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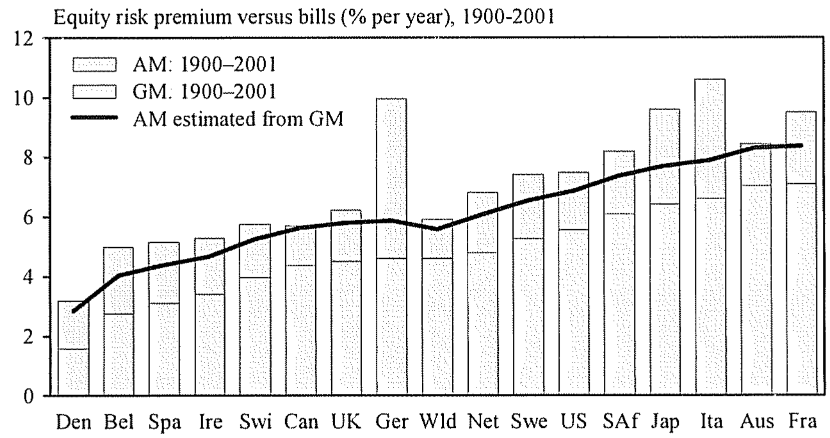
13. For example, the arithmetic mean of two equally likely returns of +25 percent and −20 percent is $(+25 - 20)/2 = 2\frac{1}{2}$ percent, while their geometric mean is zero since $(1 + 25/100) \times (1 - 20/100) - 1 = 0$.

FIGURE 5
ARITHMETIC MEAN EQUITY RISK PREMIA RELATIVE TO BILLS, 1900–2001



Source: Dimson, Marsh and Staunton, Triumph of the Optimists, Princeton University Press, 2002

geometric mean premia shown by the height of the light blue portion of the bars in Figure 5. On the other hand, if future volatility were equal to the long-term historical volatility, the expected risk premia would be equal to the historical arithmetic mean risk premia, shown by the full height of the bars. However, the long-term historical standard deviation is a poor predictor of future volatility, especially since some sources of extreme volatility (such as hyperinflation) are unlikely to recur. We therefore need estimates of expected future risk premia that are conditional on current predictions for market volatility.

When returns are distributed lognormally, the geometric and arithmetic means are linked by the standard deviation (or volatility) of returns. We therefore estimate the expected future arithmetic mean premium for each country, replacing the historical difference between the arithmetic and geometric means with a difference based on contemporary risk estimates. For expositional simplicity, even though the volatility of one stock market is not in reality the same as another, we assume a current volatility level for all sixteen national markets of 16 percent, and for the world index of 14 percent. The resulting estimates of the arithmetic mean premia relative to bills are shown by the dark blue line-plot in Figure 5.

For those wishing to forecast future arithmetic mean risk premia by extrapolating from the long-run historical annualized premia, the premia illustrated by the line plot in Figure 5 are the ones to use. The historical equity risk premium, adjusted to current levels of market volatility, is estimated as 6.8 percent for the United States, and 5.6 percent for the world index.

THE EXPERTS' CONSENSUS

In refocusing on the expected future risk premium, however, we must do more than extrapolate from the past. The question of what equity premium we can expect has, for years, been a source of controversy. In late 1998 Ivo Welch studied the opinions of 226 financial economists who were asked to forecast the thirty-year arithmetic mean equity risk premium [14].

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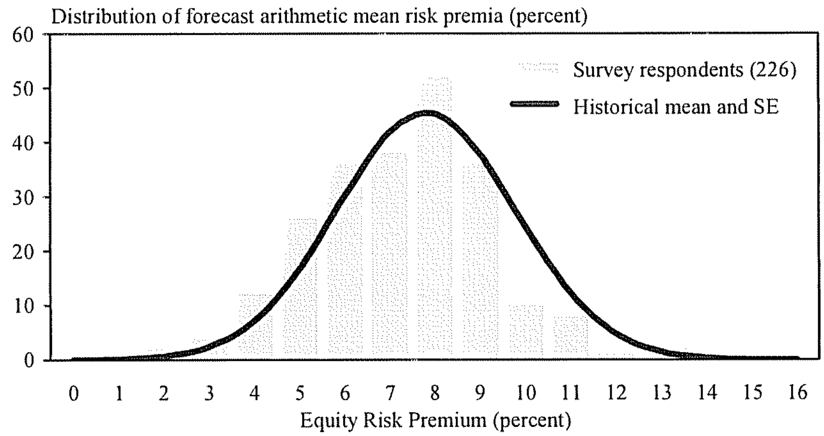
14 Welch, I, "Views of Financial Economists on the Equity Premium and Other Issues," *Journal of Business*, Vol 73, 2000, pp 501-537

FIGURE 6
FINANCIAL ECONOMISTS' RISK PREMIUM FORECASTS AND MARKET HISTORY



The bars in Figure 6 show the distribution of the responses. The mean forecast was 7.1 percent; the median was 7.0 percent, and the range ran from 1 to 15 percent.

While the bars in Figure 6 show the distribution of survey responses, the curved line represents the normal distribution based on the mean over approximately a century and the associated standard error for the US equity risk premium. The spread in both distributions indicates that the uncertainty across financial experts about the risk premium is as large as the uncertainty that arises from statistical analysis of historical returns.

Most respondents to the Welch survey would have regarded the Ibbotson Associates yearbook as the definitive study of the historical US risk premium. The first bar of Figure 7 shows that the 1926-98 arithmetic risk premium computed from Ibbotson data was 8.8 percent per year. The second bar shows that the key finance textbooks were on average suggesting a premium of 8.5 percent, a little below the Ibbotson figure. The textbook authors may have based their views on earlier, slightly lower, Ibbotson estimates, or else they were shading the Ibbotson estimates downward. The Welch survey mean is in turn lower than the textbook figure, but since respondents claimed to lower their forecasts when the equity market rises, this difference may be attributed to the market's strong performance in the 1990s. Interestingly, the third and fourth bars of Figure 7 show that the survey respondents also perceived the profession's consensus to be higher than it really was. That is, they thought the mean was around 0.8 percent higher than the 7.1 percent average revealed in the survey.

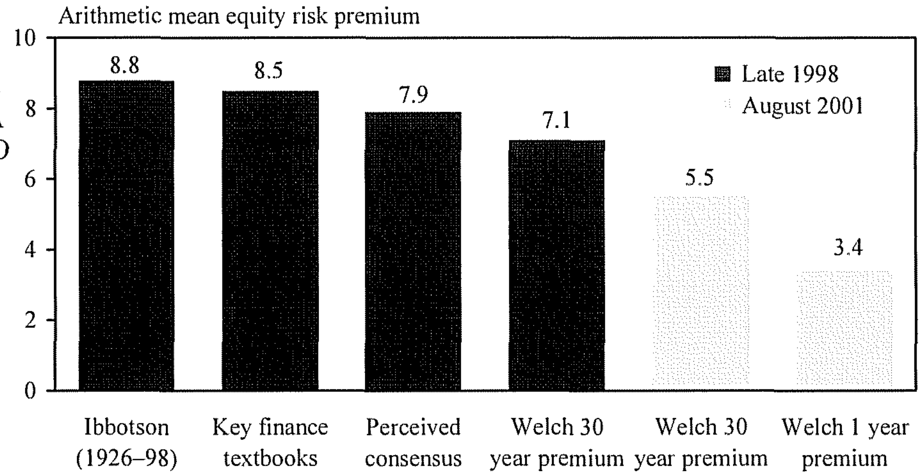
These survey and textbook figures represent what was being taught at the end of the 1990s in the world's leading business schools and economics departments in the United States and around the world. As such, these estimates were also widely used by investors, finance professionals, corporate executives, regulators, lawyers and consultants. Their influence extended from the classroom to the dealing room, to the boardroom, and to the courtroom.

New opinions

Whether Welch's survey mean of 7.1 percent was appropriate is another matter. A large number of respondents were calibrating their forecasts relative to the longest-run historical benchmark available from Ibbotson, and then shading the historical number downward based on subjective factors, including their judgement of the impact of strong market performance in the late 1990s. By 2001, longer-term estimates of the US arithmetic mean equity premium

FIGURE 7

ESTIMATED ARITHMETIC RISK PREMIA RELATIVE TO BILLS, 1998 AND 2001



were gaining publicity. Including pre-1926 data, and extending the period through the start of the new millennium, the 1900-2000 mean premium was 1.1 percent lower than the Ibbotson estimate on the left-hand side of Figure 7. At the same time, survey respondents who sought to predict a premium below the consensus might have been encouraged by publication of the survey to further reduce their estimates.

In August 2001, Welch updated his earlier survey, receiving responses from 510 finance and economics professors[15]. He found that respondents to the follow-up questionnaire had revised downward their estimates of the long-term arithmetic mean risk premium by an average of 1.6 percent. Over a thirty-year horizon they now estimated an equity premium averaging 5.5 percent, and over a one-year horizon, an equity premium averaging 3.4 percent (see Figure 7). The mean premia were the same for those who had previously participated in the earlier survey and those who were taking part for the first time. Although respondents to the earlier survey had indicated that, on average, a bear market would raise their equity premium forecast, Welch (2001) reports that "This is in contrast with the observed findings: it appears as if the recent bear market correlates with lower equity premium forecasts, not higher equity premium forecasts".

Predictions of the long-term equity premium should not be so sensitive to short-term stock market fluctuations, especially in the direction and magnitude revealed by Welch's follow-up survey in 2001. While it is possible that one-year required rates of return fluctuate markedly, it is unlikely that thirty-year expectations can be so volatile. The changing consensus may, however, reflect the new approaches to estimating the premium and /or new facts about long-term stock market performance, such as evidence that other countries have typically had historical premia that were lower than the United States.

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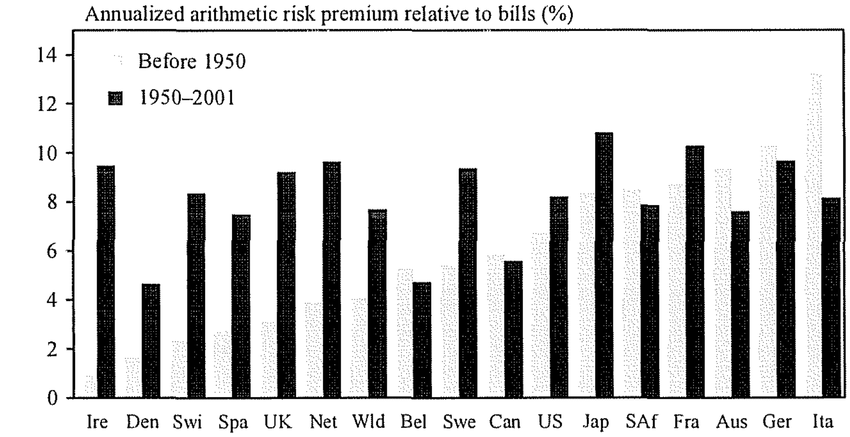
15 Welch, I, "The Equity Premium Consensus Forecast Revisited," Working paper, Yale School of Management, September 2001

FIGURE 8

PREMIA RELATIVE TO BILLS, FIRST 50 YEARS VERSUS THE NEXT 52 YEARS



Germany excludes 1922-23. Switzerland commences in 1911.
Source: Dimson, Marsh and Staunton, Triumph of the Optimists, Princeton University Press, 2002

REVISITING HISTORY

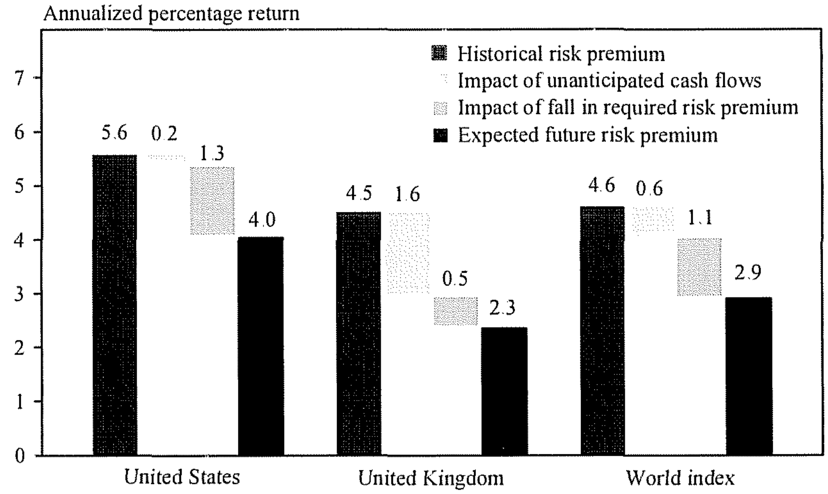
The wide dispersion of estimates, together with the dramatic decline in the consensus premium between 1998 and 2001, reinforces the need to better understand the historical record. However, since history may have been kind to (or harsh on) stock market investors, there are coherent arguments for going beyond raw historical estimates. First, the whole idea of using the achieved risk premium to forecast the required risk premium depends on having a long enough period to iron out good and bad luck, yet as we noted earlier, even with 102 years of data our estimates are imprecise. Second, the expected equity risk premium could for good reasons vary over time. Third, we must take account of the fact that stock market outcomes are influenced by many factors, some of which (like removal of trade barriers) may be non-repeatable, which implies projections for the premium that deviate from the past.

A comparison between the first and second halves of our 102-year period makes the point. Over the first half of the twentieth century, the arithmetic average world equity risk premium relative to bills was 4.1 percent, whereas over the period 1950–2001, it was 7.7 percent. Figure 8 shows that most of the sixteen countries had lower mean premia in the first half-century, with Australia, Italy, Belgium, and South Africa being the exceptions. The sixteen-country (unweighted) mean of the arithmetic risk premia in the first half of the twentieth century was 6.0 percent, versus 8.2 percent in the next fifty-two years. The pattern for the equity premium relative to bonds (not shown in Figure 8) is similar: a pre-1950 mean of 5.5 percent as compared to 7.1 percent over the following fifty-two years.

The large risk premia achieved during the second half of the twentieth century are attributable to three factors. First, there was unprecedented growth in productivity and efficiency, accelerating technological change, and enhancements to the quality of management and corporate governance. As Europe, North America, and the Asia-Pacific region emerged from the turmoil of the Second World War, expectations for improvement were limited to what could be imagined. Reality almost certainly exceeded investors' expectations. Corporate cash flows grew faster than investors anticipated, and this higher growth is now known to the market and built into higher stock prices.

FIGURE 9

INFERRING EXPECTATIONS FROM THE HISTORICAL PREMIUM



Source: Dimson, Marsh and Staunton, Triumph of the Optimists, Princeton University Press, 2002

Second, stock prices have also risen because of a fall in the required rate of return due to diminished business and investment risk. Business risk diminished as the economic and political lessons of the twentieth century were learned, international trade flows increased, and the Cold War ended. Investment risk diminished over time as investors gained the benefits of diversification, both domestically (through a wider range of quoted securities and industries[16], and through intermediaries such as mutual funds) and internationally (with the disappearance of impediments to foreign investment). Diversification allows investors to lower their risk exposure without detriment to expected return. Finally, transaction and monitoring costs are also lower now than a century ago. Factors such as these, which led to a reduction in the required risk premium, have contributed further to the upward re-rating of stock prices.

To convert from a pure historical estimate of the risk premium into a forward-looking projection, we need to reverse-engineer the factors that drove up stock markets over the last 102 years. The simplest idea would be to infer the impact on returns of the historical changes in dividend yield. But we can go beyond this, as shown in Figure 9. The left-hand panel of Figure 9 relates to the US equity market, the centre panel to the UK market, and the right-hand panel to the world market. Within each panel, the first bar portrays the historical *annualized* risk premium of the equity market. This includes the contribution from unanticipated growth in cash flows and the gain from falls in the required risk premium. We therefore deduct the impact of these two factors. What remains in the right-hand bar of each panel is an estimate of the prospective risk premium demanded by investors as compensation for the risks of equity investment. We explain below how we quantify the deductions in the two centre bars of each panel, but the key qualitative point is that the prospective risk premium is lower than the raw historical risk premium.

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16 At the start of our research period in 1900, US domestic investors would have found it much harder than today to construct a well-diversified portfolio. At the start of 1900, there were just 123 stocks listed on the New York Stock Exchange, and a single industry, railroads, accounted for 63 percent of their total market value. See Chapter 2, Dimson, E, P R Marsh, and M Staunton, *Triumph of the Optimists: 101 Years of Global Investment Returns*, Princeton University Press, 2002.

Unanticipated growth

To apply this framework, we need some notion of when cash flows (proxied here by equity dividends) have exceeded or fallen short of expectations. A simple approach that is commonly used today for forecasting the long-run dividend growth rate is to extrapolate from previous long-term dividend growth. The long-term real dividend growth rate is then used to make a naive projection of future real growth. That is, we estimate the product of *1 + Year 1 annual growth* multiplied by *1 + Year 2 annual growth* and so on to year *n*. We then compute the n^{th} root of this product, which is equal to *1 + Projected growth.* To summarize, we calculate the annualized real dividend growth rate to each year-end, over periods that start in 1900.

We assume that at every December 31^{st}, investors compare the year's real dividend growth to the real growth rate that would have been projected as at January 1^{st} of that year. The difference is defined as *1 + Annual dividend growth* divided by *1 + Projected growth*, minus *1*. This error in projecting dividend growth may be thought of as the unanticipated growth rate in dividends. The unanticipated changes in dividend growth are compounded together to produce an estimate of their annualized impact over the last century. This is clearly a rather ad hoc measure of unanticipated real dividend growth, but it suffices to illustrate the general idea. Defined this way, Figure 9 shows that the stock price impact of unanticipated dividend growth over the period from 1900 to 2001 is 0.2 percent per year for the United States, 1.6 percent per year in the United Kingdom, and 0.6 percent per year for the world equity market.

Since 1900, there has also been a dramatic change in the valuation basis for equity markets. The price/dividend ratio (the reciprocal of the dividend yield) at the start of 1900 was twenty-three in both the United States and the United Kingdom, but by the start of 2002, the US ratio had risen to eighty-one and the UK ratio to thirty-nine. Undoubtedly, this change is in part a reflection of expected future growth in real dividends, so we could in principle decompose the impact of this valuation change into both an element that reflects changes in required rates of return, and an element that reflects enhanced growth expectations.

To keep things simple, we assume that the increase in the price/dividend ratio is attributable solely to a long-term fall in the required risk premium for equity investment. Given this assumption, Figure 9 shows that the stock price impact of the fall in the required risk premium since 1900 is 1.6 percent per year in the United States and 0.5 percent per year in the United Kingdom. This, together with the impact of unanticipated dividend growth, must be deducted from the historical risk premium.

To estimate the expected future risk premia, we must deduct the impact of both unanticipated cash flows and the fall in the required risk premium from our historical premia. The first of these adjustments can be thought of as the impact of good luck, while the second can be viewed as the effect of re-rating. Figure 9 shows quite large differences in the relative importance of these factors between the United States and the United Kingdom. In particular, for the US market, good luck appears to have had a smaller impact, and re-rating a larger influence. This arises partly from our using dividends as a proxy for unexpected cash flows and changes in the dividend price ratio as a proxy for re-rating. In the United States, the rapid growth of stock repurchases and the trend toward "disappearing dividends"[17] makes it harder

17 See Fama, E F and K R French, "Disappearing Dividends: Changing Firm Characteristics or Lower Propensity to Pay", *Journal of Financial Economics*, Vol 60, 2001, pp 3-43

to disentangle these effects. The United States is the outlier among our sixteen countries[18], and in judging the relative contribution of unanticipated cash flows versus the impact of the fall in the required risk premium, the UK pattern may be more informative (see Figure 9).

The net effect of deducting the two adjustments from the historical risk premia is shown in the final bar of each of the three panels in Figure 9. These indicate an expected future geometric risk premium of 4.0 percent for the United States, 2.3 percent for the United Kingdom, and 2.9 percent for the world equity market. Our estimates for the United States are similar to those obtained recently by Fama and French using a related approach[19]. Also based on dividend yields and dividend growth estimates, Fama and French use the Gordon model to compute the US equity premium from 1872–1999. They find a premium of 3.8 percent before 1949, and a premium of 3.4 percent for the subsequent period. They argue that the difference between these estimates and the larger ex post risk premium based on historical realized returns is attributable to a reduction since 1949 in investors' required rate of return.

EXPECTED RISK PREMIA

If they are to be used as prospective risk premia, our annualized figures need to be converted into arithmetic means, as explained earlier. Using a projected standard deviation for US and UK equities of 16 percent, the prospective arithmetic risk premia for the United States is 5.3 percent, while the premium for the United Kingdom is 3.6 percent. Using a slightly lower standard deviation for the world index of 14 percent, the prospective arithmetic risk premium for the world index is 3.9 percent. Whichever country one focuses on, our forward-looking predictions for the equity risk premium are lower than the historically based projections reviewed earlier.

A literal interpretation of historical averages might suggest that France has a higher equity risk premium, while Denmark's is lower. While there are obviously differences in risk between markets, this is unlikely to account for cross-sectional differences in historical premia. Indeed, much of the cross-country variation in historical equity premia is attributable to country-specific historical events that will not recur. When making future projections, there is a strong case, particularly given the increasingly international nature of capital markets, for taking a global rather than a country-by-country approach to determining the prospective equity risk premium.

However, just as there must be some true differences across countries in their riskiness, there must also be variation over time in the levels of stock market risk. It is well known that stock market volatility wanders over time, and it is likely that the "price" of risk—namely the risk premium—also fluctuates over time. In the days following September 11, 2001 for example, financial market risk was high, and it is likely that the equity premium demanded by investors was also high. This depressed the market. If the terror had escalated further, the market may have collapsed; but Armageddon did not arrive and the market bounced back.

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18 Compared with the United States, stock repurchases have been far less prevalent in the other countries In Europe, the United Kingdom has the highest level of buybacks, but even UK repurchases are small compared with the United States See section 11 6 of Dimson, E, P R Marsh, and M Staunton, *Triumph of the Optimists: 101 Years of Global Investment Returns*, Princeton University Press, 2002

19 Fama, E F and K R French, "The Equity Premium", *Journal of Finance*, Vol 57, 2002, pp 637-59

There were similar considerations a generation earlier during the Cuban missile crisis—another Armageddon that was averted. Clearly, at such times risk premia are above average. However, it is difficult to predict premia from the rolling ten-year averages depicted earlier in Figure 4. Indeed, it is difficult to infer expected premia from any analysis of historical excess returns. It may be better to use a "normal" equity premium most of the time, and to deviate from this prediction only when there are compelling economic reasons to suppose expected premia are unusually high or low.

CONCLUSION

The equity premium is the difference between the return on risky stocks and the return on safe bonds. The equity risk premium is central to corporate finance and investment. It is often described as the most important number in finance. Yet it is not clear how big the equity premium has been in the past, or how large it is today.

This paper has presented new evidence on the historical risk premium for sixteen countries over 102 years. Our estimates are lower than frequently quoted historical averages such as the Ibbotson Associates' figures for the United States and the earlier Barclays Capital and CSFB studies for the United Kingdom. The differences arise from previous bias in index construction for the United Kingdom, and, for both countries, from our choice of a longer time frame from 1900–2001, which incorporates the earlier part of the twentieth century, as well as the opening years of the new millennium. In addition, our global focus results in somewhat lower risk premia than hitherto assumed, since prior views have been heavily influenced by the experience of the United States, yet we find that the US risk premium has been somewhat higher than the average for the other fifteen countries.

The historical equity premium is often presented in the form of an annualized rate of return, which summarizes past performance in one number. For the future, what is required is the arithmetic mean of the distribution of equity premia, which is larger than the geometric mean. For markets that have been particularly volatile, the arithmetic mean of past equity premia may exceed the geometric mean premium by several percentage points.

In forecasting the future arithmetic mean premium, investors or companies who believe they can expect the same annualized risk premium as they have received in the past still need to adjust for the differences between historical market volatility and the volatility that we might anticipate today. More fundamentally, however, we have argued that past returns have been flattered by the impact of good luck and re-rating. Since the middle of the last century, equity cash flows almost certainly exceeded expectations, and the required rate of return doubtless fell as investment risk declined and the scope for diversification increased. Stock markets rose for reasons that are unlikely to be repeated. This means that when seeking forecasts for the future, historical risk premia should be adjusted downward for the impact of these factors.

We have illustrated one approach that can be used to make such adjustments. The result is a set of forward-looking, geometric mean risk premia for the United States, United Kingdom and for the world all falling within a range of around 2½ to 4 percent, and a corresponding set of arithmetic mean risk premia falling in a range of around 3½ to 5¼ percent. These estimates are not only far lower than the historical premia quoted in most textbooks, but they are also lower than those cited in surveys of finance academics.

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MODERN PORTFOLIO THEORY AND INVESTMENT ANALYSIS

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ied in valuation models. We review a few of the more widely used ones here. In particular, we examine three sets of growth assumptions. They are:

1. Constant growth over an infinite amount of time.[7]
2. Growth for a finite number of years at a constant rate, then growth at the same rate as a typical firm in the economy from that point on.[8]
3. Growth for a finite number of years at a constant rate, followed by a period during which growth declines to a steady state level over a second period of years.[9] Growth is then assumed to continue at the steady state level into the indefinite future.

We can, for obvious reasons, refer to these three models respectively as one-period, two-period, and three-period growth models. It should be equally as obvious that we could have a four-period, five-period, or N-period growth model.

As we move down this list of models we are assuming more complex growth patterns for a company. We may be gaining the potential to more accurately forecast what a company will do, but we are asking the analyst to supply not only more data, but data increasingly difficult to forecast. As the type of data we ask to have forecasted becomes more difficult and the amount of information grows, forecasts are likely to contain less information and more random noise. As models become more complex, a point of diminishing returns is reached. Where this point is cannot be answered in the abstract; it is a function of the forecasting skills of the organization employing the model. Thus, the question can only be answered by examining the forecast ability of the organization that is using, or proposes using, one or more valuation models. Let us now turn to an examination of some of the DCF models mentioned above.

Constant Growth Model

One of the best known and certainly the simplest DCF model assumes that dividends will grow at the same rate (g) into the indefinite future. Under this assumption the value of a share of stock is

$$P = \frac{D}{(1+k)} + \frac{D(1+g)}{(1+k)^2} + \frac{D(1+g)^2}{(1+k)^3} + \cdots + \frac{D(1+g)^{N-1}}{(1+k)^N} + \cdots$$

[7] See Williams [73] or Gordon [40] for discussion of models of this type

[8] See Malkiel [63] for the presentation of a model of this type

[9] See Molodovsky, May, and Chottinger [67] for the presentation of a model of this type

Using the formula for the sum of a geometric progression,[10]

$$P = \frac{D}{k - g} \tag{15.5}$$

This model states that the price of a share of stock should be equal to next year's expected dividend divided by the difference between the appropriate discount rate for the stock and its expected long term growth rate. Alternatively, this model can be stated in terms of the rate of return on a stock as

$$k = D/P + g \tag{15.6}$$

The constant growth model is often defended as the model that arises from the following assumptions: The firm will maintain a stable dividend policy (keep its retention rate constant) and earn a stable return on new equity investment over time. If we let b stand for the fraction of earnings retained within the firm, r stand for the rate of return the firm will earn on all new investments, and I_t stand for investment at t, we get a very simple expression for growth. The formula requires an estimate of the growth in dividends over time. We can derive an expression for the growth in dividends by first examining the growth in earnings. Growth in earnings arises from the return on new investments. We can write earnings at any moment as

$$E_t = E_{t-1} + rI_{t-1}$$

If the firm's retention rate is constant, then

$$E_t = E_{t-1} + rbE_{t-1} = E_{t-1}(1 + rb)$$

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[10] The sum of a geometric progression is given by
Sum = First term $[1 - (\text{common ratio})^N]/(1 - \text{common ratio})$
where N is the number of terms over which we are summing. For this model we have

$$P = \frac{\dfrac{D}{1+k}\left[1 - \left(\dfrac{1+g}{1+k}\right)^N\right]}{1 - \dfrac{1+g}{1+k}}$$

as N goes to infinity and

$$\left(\frac{1+g}{1+k}\right)^N$$

goes to zero, we obtain the formula in the text.

Growth in earnings is the percentage change in earnings, or

$$g = \frac{E_t - E_{t-1}}{E_{t-1}} = \frac{E_{t-1}(1 + rb) - E_{t-1}}{E_{t-1}} = rb$$

Since a constant proportion of earnings is assumed to be paid out each year, the growth in earnings equals the growth in dividends, or

$$g_E = g_D = rb$$

Using this expression for growth, we can rewrite Equations (15.5) and (15.6) as[11]

$$P = \frac{D}{k - rb} \qquad k = \frac{D}{P} + rb \tag{15.5b}$$

It is worthwhile examining the implications of this model for the growth in stock prices over time. The growth in stock price is

$$g_P = \frac{P_{t+1} - P_t}{P_t}$$

Recognizing that P_t can be defined by Equation (15.5b) and that P_{t+1} is also given by Equation (15.5b) except that D must be replaced by $D(1 + br)$, we find

$$g_P = br$$

Thus, under the one-period model dividends, earnings and prices are all expected to grow at the same rate. It might be worthwhile to point out the key role expectations about the future profitability of investment opportunities play in this model. The rate of return on new investments can be expressed as a fraction (perhaps larger than one) of the rate of return security holders require, or

$$r = ck$$

Substituting this in Equation (15.6) and rearranging

$$k = \frac{(1 - b)E}{(1 - cb)P}$$

[11] Analysts frequently like to work in terms of price earnings multiples. Since $D = (1 - b)E$, if we divide both sides of Equation (15.5b) by earnings, we have

$$\frac{P}{E} = \frac{1 - b}{k - br}$$

Notice that if the firm has no extraordinary investment opportunities ($r = k$), then $c = 1$ and the rate of return that security holders require is simply the inverse of the stock's price earnings ratio. On the other hand, if the firm has investment opportunities that are expected to offer a return above that required by the firm's stockholders ($c > 1$), the earnings price ratio at which the firm sells will be below the rate of return required by investors.[12]

Let us spend a moment examining how the single-period model might be used to select stocks. One way is to predict next year's dividends, the firm's long term growth rate, and the rate of return stockholders require for holding the stock. Equation (15.5) could then be solved for the theoretical price of the stock that could be compared with its present price. Stocks that have theoretical prices above their actual prices are candidates for purchase; those with theoretical prices below their actual price are candidates for sale. The same procedure could be followed using the equation in footnote 11 with respect to price earnings ratios.

Another way to use the DCF approach is to find the rate of return implicit in the price at which the stock is now selling. This can be done by substituting the current price, estimated dividend, and estimated growth rate into Equation (15.6) and solving for the discount rate that equates the present price with the expected flow of future dividends. If this rate is higher than the rate of return considered appropriate for the stock, given its risk, it is a candidate for purchase.

We illustrate the use of the single-period model with a simple example. In the recent past, IBM's stock was selling for \$65 a share. At that time IBM's earnings were \$3.99 per share and it paid a \$2.00 dividend. At that time a major brokerage firm was estimating IBM's long term growth rate at 12% and its dividend payout rate at 50%. If we assume 13% is an appropriate discount rate for IBM, we would compute a theoretical price of

$$P = \frac{2.00}{0.13 - 0.12} = \$200$$

While IBM's stock would seem to be undervalued selling at \$65 a share, notice the sensitivity of this valuation equation to both the estimate of the appropriate discount rate and the estimate of the long term growth rate. For example, if IBM's growth rate was estimated to be 9% rather than 12%, its theoretical price would be ¼ as large or \$50.

It seems logical to assume that firms which have grown at a very high rate will not continue to do so into the infinite future. Likewise, firms with very poor growth might improve in the future. While a single growth rate can be found that

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[12] For a detailed analysis of the roll that investment opportunities play in the valuation of securities, see Elton and Gruber [32].

Full text of Federal Reserve's Open Market Com

Full text of Fed statement

Updated 43m ago

Information received since the Federal Open Market Committee met in December suggests that the economy has been expanding moderately, notwithstanding some slowing in global growth. While indicators point to some further improvement in overall labor market conditions, the unemployment rate remains elevated. Household spending has continued to advance, but growth in business fixed investment has slowed, and the housing sector remains depressed. Inflation has been subdued in recent months, and longer-term inflation expectations have remained stable.

Consistent with its statutory mandate, the Committee seeks to foster maximum employment and price stability. The Committee expects economic growth over coming quarters to be modest and consequently anticipates that the unemployment rate will decline only gradually toward levels that the Committee judges to be consistent with its dual mandate. Strains in global financial markets continue to pose significant downside risks to the economic outlook. The Committee also anticipates that over coming quarters, inflation will run at levels at or below those consistent with the Committee's dual mandate.

To support a stronger economic recovery and to help ensure that inflation, over time, is at levels consistent with the dual mandate, the Committee expects to maintain a highly accommodative stance for monetary policy. In particular, the Committee decided today to keep the target range for the federal funds rate at 0 to 1/4 percent and currently anticipates that economic conditions--including low rates of resource utilization and a subdued outlook for inflation over the medium run--are likely to warrant exceptionally low levels for the federal funds rate at least through late 2014.

STORY: What the Fed action means
MORE: Fed's economic projections
MORE: Fed's new voting members

The Committee also decided to continue its program to extend the average maturity of its holdings of securities as announced in September. The Committee is maintaining its existing policies of reinvesting principal payments from its holdings of agency debt and agency mortgage-backed securities in agency mortgage-backed securities and of rolling over maturing Treasury securities at auction. The Committee will regularly review the size and composition of its securities holdings and is prepared to adjust those holdings as appropriate to promote a stronger economic recovery in a context of price stability.

MONEY

Voting for the FOMC monetary policy action were: Ben S. Bernanke, Chairman; William C. Dudley, Vice Chairman; Elizabeth A. Duke; Dennis P. Lockhart; Sandra Pianalto; Sarah Bloom Raskin; Daniel K. Tarullo; John C. Williams; and Janet L. Yellen. Voting against the action was Jeffrey M. Lacker, who preferred to omit the description of the time period over which economic conditions are likely to warrant exceptionally low levels of the federal funds rate.

Posted 2h 21m ago | Updated 43m ago

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FEDERAL RESERVE statistical release

H.15 (519) SELECTED INTEREST RATES
Yields in percent per annum

For use at 2:30 p.m. Eastern Time
January 30, 2012

Instruments	2012 Jan 23	2012 Jan 24	2012 Jan 25	2012 Jan 26	2012 Jan 27	Week Ending Jan 27	Week Ending Jan 20	2011 Dec
Federal funds (effective)[1 2 3]	0.09	0.09	0.08	0.08	0.09	0.09	0.09	0.07
Commercial Paper[3 4 5 6]								
Nonfinancial								
1-month	0.09	0.07	0.09	0.08	0.07	0.08	0.09	0.10
2-month	0.11	0.12	0.13	0.11	0.10	0.11	0.11	0.11
3-month	0.15	0.12	0.12	0.15	n.a.	0.14	0.14	0.14
Financial								
1-month	0.12	0.11	n.a.	0.12	n.a.	0.12	0.04	0.06
2-month	n.a.	0.10	n.a.	n.a.	n.a.	0.10	0.09	0.10
3-month	0.23	0.21	0.32	n.a.	0.31	0.27	0.19	0.18
CDs (secondary market)[3 7]								
1-month	0.19	0.19	0.19	0.19	0.18	0.19	0.19	0.24
3-month	0.37	0.37	0.36	0.36	0.35	0.36	0.36	0.49
6-month	0.57	0.57	0.56	0.56	0.56	0.56	0.57	0.67
Eurodollar deposits (London)[3 8]								
1-month	0.35	0.35	0.35	0.35	0.35	0.35	0.34	0.35
3-month	0.50	0.50	0.50	0.50	0.50	0.50	0.48	0.50
6-month	0.70	0.70	0.70	0.70	0.78	0.72	0.70	0.72
Bank prime loan[2 3 9]	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25
Discount window primary credit[2 10]	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75
U.S. government securities								
Treasury bills (secondary market)[3 4]								
4-week	0.03	0.02	0.03	0.04	0.05	0.03	0.03	0.00
3-month	0.04	0.04	0.04	0.05	0.06	0.05	0.04	0.01
6-month	0.07	0.07	0.07	0.08	0.08	0.07	0.07	0.05
1-year	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Treasury constant maturities								
Nominal[11]								
1-month	0.03	0.02	0.03	0.04	0.05	0.03	0.03	0.00
3-month	0.04	0.04	0.04	0.05	0.06	0.05	0.04	0.01
6-month	0.07	0.07	0.07	0.08	0.08	0.07	0.07	0.05
1-year	0.12	0.12	0.12	0.12	0.12	0.12	0.11	0.12
2-year	0.26	0.24	0.22	0.22	0.22	0.23	0.24	0.26
3-year	0.39	0.39	0.34	0.31	0.32	0.35	0.36	0.39
5-year	0.93	0.92	0.81	0.77	0.75	0.84	0.85	0.89
7-year	1.51	1.49	1.40	1.34	1.31	1.41	1.39	1.43
10-year	2.09	2.08	2.01	1.96	1.93	2.01	1.96	1.98
20-year	2.82	2.82	2.78	2.74	2.71	2.77	2.68	2.67
30-year	3.15	3.15	3.13	3.10	3.07	3.12	3.00	2.98
Inflation indexed[12]								
5-year	-0.84	-0.89	-1.02	-1.09	-1.13	-0.99	-0.89	-0.78
7-year	-0.46	-0.50	-0.62	-0.68	-0.71	-0.59	-0.52	-0.44
10-year	0.02	-0.01	-0.12	-0.16	-0.18	-0.09	-0.08	-0.03
20-year	0.66	0.62	0.53	0.51	0.49	0.56	0.52	0.56
30-year	0.84	0.82	0.76	0.74	0.73	0.78	0.74	0.78
Inflation-indexed long-term average[13]	0.54	0.53	0.45	0.42	0.41	0.47	0.45	0.51
Interest rate swaps[14]								
1-year	0.54	0.55	0.55	0.51	0.53	0.54	0.56	0.67
2-year	0.58	0.59	0.58	0.53	0.54	0.56	0.58	0.71
3-year	0.71	0.72	0.70	0.61	0.63	0.67	0.69	0.83
4-year	0.95	0.95	0.94	0.81	0.82	0.89	0.90	1.05
5-year	1.23	1.23	1.21	1.06	1.07	1.16	1.15	1.29
7-year	1.72	1.71	1.69	1.55	1.55	1.65	1.61	1.72
10-year	2.20	2.19	2.17	2.05	2.05	2.13	2.06	2.13
30-year	2.87	2.86	2.85	2.80	2.81	2.84	2.70	2.70
Corporate bonds								
Moody's seasoned								
Aaa[15]	3.91	3.92	3.93	3.88	3.85	3.90	3.83	3.93
Baa	5.33	5.33	5.32	5.24	5.21	5.29	5.20	5.25
State & local bonds[16]				3.68		3.68	3.60	3.95
Conventional mortgages[17]				3.98		3.98	3.88	3.96

See overleaf for footnotes.
n.a. Not available.

Footnotes

1. The daily effective federal funds rate is a weighted average of rates on brokered trades.
2. Weekly figures are averages of 7 calendar days ending on Wednesday of the current week; monthly figures include each calendar day in the month.
3. Annualized using a 360-day year or bank interest.
4. On a discount basis.
5. Interest rates interpolated from data on certain commercial paper trades settled by The Depository Trust Company. The trades represent sales of commercial paper by dealers or direct issuers to investors (that is, the offer side). The 1-, 2-, and 3-month rates are equivalent to the 30-, 60-, and 90-day dates reported on the Board's Commercial Paper Web page (www.federalreserve.gov/releases/cp/).
6. Financial paper that is insured by the FDIC's Temporary Liquidity Guarantee Program is not excluded from relevant indexes, nor is any financial or nonfinancial commercial paper that may be directly or indirectly affected by one or more of the Federal Reserve's liquidity facilities. Thus the rates published after September 19, 2008, likely reflect the direct or indirect effects of the new temporary programs and, accordingly, likely are not comparable for some purposes to rates published prior to that period.
7. An average of dealer bid rates on nationally traded certificates of deposit.
8. Source: Bloomberg and CTRB ICAP Fixed Income & Money Market Products.
9. Rate posted by a majority of top 25 (by assets in domestic offices) insured U.S.-chartered commercial banks. Prime is one of several base rates used by banks to price short-term business loans.
10. The rate charged for discounts made and advances extended under the Federal Reserve's primary credit discount window program, which became effective January 9, 2003. This rate replaces that for adjustment credit, which was discontinued after January 8, 2003. For further information, see www.federalreserve.gov/boarddocs/press/bcreg/2002/200210312/default.htm. The rate reported is that for the Federal Reserve Bank of New York. Historical series for the rate on adjustment credit as well as the rate on primary credit are available at www.federalreserve.gov/releases/h15/data.htm.
11. Yields on actively traded non-inflation-indexed issues adjusted to constant maturities. The 30-year Treasury constant maturity series was discontinued on February 18, 2002, and reintroduced on February 9, 2006. From February 18, 2002, to February 9, 2006, the U.S. Treasury published a factor for adjusting the daily nominal 20-year constant maturity in order to estimate a 30-year nominal rate. The historical adjustment factor can be found at www.treasury.gov/resource-center/data-chart-center/interest-rates/. Source: U.S. Treasury.
12. Yields on Treasury inflation protected securities (TIPS) adjusted to constant maturities. Source: U.S. Treasury. Additional information on both nominal and inflation-indexed yields may be found at www.treasury.gov/resource-center/data-chart-center/interest-rates/.
13. Based on the unweighted average bid yields for all TIPS with remaining terms to maturity of more than 10 years.
14. International Swaps and Derivatives Association (ISDA®) mid-market par swap rates. Rates are for a Fixed Rate Payer in return for receiving three month LIBOR, and are based on rates collected at 11:00 a.m. Eastern time by Garban Intercapital plc and published on Reuters Page ISDAFIX®1. ISDAFIX is a registered service mark of ISDA. Source: Reuters Limited.
15. Moody's Aaa rates through December 6, 2001, are averages of Aaa utility and Aaa industrial bond rates. As of December 7, 2001, these rates are averages of Aaa industrial bonds only.
16. Bond Buyer Index, general obligation, 20 years to maturity, mixed quality; Thursday quotations.
17. Contract interest rates on commitments for fixed-rate first mortgages. Source: Primary Mortgage Market Survey® data provided by Freddie Mac.

Note: Weekly and monthly figures on this release, as well as annual figures available on the Board's historical H.15 web site (see below), are averages of business days unless otherwise noted.

Current and historical H.15 data are available on the Federal Reserve Board's web site (www.federalreserve.gov/). For information about individual copies or subscriptions, contact Publications Services at the Federal Reserve Board (phone 202-452-3244, fax 202-728-5886).

Description of the Treasury Nominal and Inflation-Indexed Constant Maturity Series

Yields on Treasury nominal securities at "constant maturity" are interpolated by the U.S. Treasury from the daily yield curve for non-inflation-indexed Treasury securities. This curve, which relates the yield on a security to its time to maturity, is based on the closing market bid yields on actively traded Treasury securities in the over-the-counter market. These market yields are calculated from composites of quotations obtained by the Federal Reserve Bank of New York. The constant maturity yield values are read from the yield curve at fixed maturities, currently 1, 3, and 6 months and 1, 2, 3, 5, 7, 10, 20, and 30 years. This method provides a yield for a 10-year maturity, for example, even if no outstanding security has exactly 10 years remaining to maturity. Similarly, yields on inflation-indexed securities at "constant maturity" are interpolated from the daily yield curve for Treasury inflation protected securities in the over-the-counter market. The inflation-indexed constant maturity yields are read from this yield curve at fixed maturities, currently 5, 7, 10, and 20 years.

HabrFlotationCosts copy.pdf

MULTI-UTILITY REGULATION
Prepared by Miriam A. Tucker

COMMISSION STAFF REPORT: A NOTE ON TRANSACTION COSTS AND THE COST OF COMMON EQUITY FOR A PUBLIC UTILITY

By David S. Habr[1]

It is not unusual for a utility company to make an upward adjustment to its estimate of the cost of common equity to recognize the fact that the utility pays all the expenses, including brokerage fees, associated with a new (primary) issue of common stock.[2] As a group, these expenses are referred to as flotation costs. The purpose of this analysis is to integrate all market transaction costs within the basic discounted cash flow (DCF) model. Specifically, a model is developed which incorporates both the flotation costs incurred by the firm when new stock is issued and the brokerage fees paid by the purchaser in the secondary market.

Although the percentage increase in the cost of common equity called for by the flotation cost adjustment may be small, three to 10 percent, the revenue effect of the adjustment can be millions of dollars.[3] Given

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[1] Economics Section, Utilities Division, Iowa Department of Commerce. The author thanks Eugene Rasmussen for helpful comments and suggestions. The analysis presented herein does not necessarily reflect the views, opinions, or policies of the NRRI, NARUC, the Iowa Department of Commerce, the Iowa State Utilities Board, or other NARUC member commissions.

[2] Commissions may also make this adjustment. For example, FERC has included an adjustment for these costs in its generic common equity return. 49 Federal Register 144, July 25, 1984, 29967.

[3] For a utility with a 50 percent common equity ratio and an income tax rate of 50 percent, an increase in the allowed return on common equity of 10 basis points (0.1 percentage points) increases the revenue requirement

(Footnote continues on next page)

this dollar impact, the proper method for measuring this cost has been discussed extensively in both the academic and trade literature (Arzac and Marcus 1981, 1983, 1984, Patterson 1983, and Howe 1984; Patterson 1981, Bierman and Hass 1984, and Brigham, Aberwold, and Garenski 1985). However, the preceding works have not considered secondary market brokerage fees even though secondary market prices are used in the applied DCF model.

The analysis is divided into three main parts. First, there is a description of the role of the common equity return in public utility ratemaking, the function of the flotation cost adjustment, and the need for a buyer incurred transaction cost adjustment. Next, the derivation of the fully integrated DCF model and a comparison of this model with the unadjusted DCF model is found. Finally, an empirical estimate of the complete transaction cost adjustment is presented.

Cost of Common Equity in Utility Ratemaking

The role of the common equity return in public utility ratemaking is to generate, ceteris paribus, an expected return sufficient to compensate the common equity owners for the risks assumed in their ownership interest in the company.[4] This is analagous to the concept of a normal profit in economic theory. The problem faced by economists and commissions alike is how to measure this cost. In utility rate proceedings, a common method used is discounted cash flow (DCF).

The DCF method is based on the proposition that the observed market price of a share of common stock simply represents the present value of its expected income stream, i.e., the market price of the stock is given by:

$$P_o = \int_o^\infty \frac{D_o e^{gt} dt}{e^{k_1 t}} \qquad (1)$$

(Footnote continued from previous page)

by $1 million for each billion dollars of rate base. For example, an increase in the allowed return on common equity from 14.00 to 14.70 percent (a five percent increase) will lead to a $3.5 million revenue increase for a utility with the above described capital structure and income tax rate and a $500 million rate base. See also Arzac and Marcus 1981.

[4] See, for example, "Re Area Rate Proceedings for Permian Basin," 75 PUR 3d, 297.

where: P_o = current market price of the stock;

D_o = current indicated annualized dividend per share;

g = expected long run dividend growth rate;

k_1 = the investors' subjective discount rate which represents the investors' expected return;

t = time.

Equation (1) can be solved for k_1 if it is assumed that $k_1 > g$.[5] This yields the general form of the model presented in utility rate cases

$$k_1 = \frac{D_0}{P_0} + g \tag{2}$$

In equation (2) the market-determined cost of common equity is equal to the dividend yield plus the expected long-term growth in dividends.[6]

In a world without transaction costs, allowing the utility to earn k_1 on the common equity portion of its rate base would generate sufficient earnings to allow common equity holder expectations of dividend payments and growth to be met. This results automatically because the amount of funds provided by the common equity owners is exactly equal to the amount of common equity funds invested in rate base. However, stock transactions are not costless. When a firm issues new stock, it traditionally pays the issuance expenses (flotation costs) out of the proceeds received. Thus, all of the funds provided by the common equity owners are not available for investment in rate base. Allowing the utility to earn k_1 on a smaller rate base will not generate earnings sufficient to cover common equity owners' expectations concerning dividend payments and growth. In other words, the cost of common equity from the firm's point of view is greater than that given by equation (2), the investors' point of view.

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[5] General observation of the market place indicates that this is a reasonable assumption. If the converse were true, the rational investor would be willing to pay an infinitely large price for the share; observed market prices are always less than this.

[6] Some analysts use a discrete form of the DCF model for regulatory purposes based on the argument that dividends are received quarterly rather than continuously. However, it can be demonstrated that a firm that earns its "k" as determined by equation (2) on a daily or continuous basis will generate a dividend stream to the common investor that is completely consistent with the dividend stream implicit in the discrete form of the model.

On the other side, the stock price used in rate cases is based on the secondary (i.e., non-new issue) market price of the firm's common stock.[7] These secondary market prices do not include the brokerage fees paid by the purchaser. Hence, the actual price paid by the purchaser is underestimated while the dividend yield portion of equation (2) and the common equity owners' expected return, k_1, are overestimated.

The end result is that a flotation cost adjustment has the effect of increasing the estimate of the cost of common equity while an adjustment for the brokerage fees paid by the purchaser in the secondary market has the effect of decreasing the estimate of the cost of common equity. These adjustments can be expected to be partially offsetting, but the net effect cannot be determined on an a priori basis.

The Model

Arzac and Marcus (1981), Bierman and Hass (1984), Howe (1984), and Patterson (1983) generally treat the flotation cost adjustment as an adjustment to the firm's allowed return as opposed to an adjustment to the market cost of common equity. The purpose of the adjustment is to allow the firm to generate the income stream that would exist in the absence of flotation costs. Bierman and Hass (1984) and Howe (1983) also propose the alternative of simply treating these costs as expense items and including them in the general cost of service without an adjustment to the firm's allowed return. That is, in this case, the allowed return would be set equal to the investor's expected return as given by equation (2).

The approach taken in developing the treatment of flotation costs in this model is a hybrid of the approaches taken by these writers. These costs are treated as a recurring item or "expense" as by Bierman and Hass (1984) and Howe (1983), but the recovery of this item is integrated into the investor's expected income stream as suggested by Arzac and Marcus (1981). This treatment facilitates the integration of the effects of the flotation costs and brokerage fees on the cost of common equity.

From the stockholder's point of view, the flotation cost allowance has the impact of assuring that total common equity will not decrease as a result of the expenses associated with the issuance of new common stock. Thus, the expected dividend stream will remain unchanged whether or not new common stock is issued. However, if the firm is expected to continuously issue new common stock, the investors will perceive their

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[7] Estimates of the price used in the dividend yield calculation range from variants of the average price during the test period to a current spot price.

shares as having two income streams, the expected dividends and the recovery of the flotation expenses.

Recovery of the flotation expenses means the investors' current dividend expectation continues to be reflected by D_0. The dividend (D_0) is paid directly to the investors while the recovery of the flotation expenses accrues to retained earnings to maintain common equity at its initial level. Assuming no investor-incurred brokerage fees, the DCF model consistent with these perceptions can be written as:

$$P_0 = \int_0^{\infty} \left[\frac{[D_0 + \left[\frac{f}{1-f}\right] sB_0]\ e^{gt}}{e^{k_2 t}} \right] dt \qquad (3)$$

where: B_0 = Current book common equity per outstanding share;

f = Flotation costs as a fraction of gross proceeds;

s = The issuance rate measured as external annual net proceeds as a fraction of current common equity.

The second term in parentheses in the numerator of the right hand side of the equation represents the income stream per current share needed to offset the expected flotation costs.[8] Under these conditions the investors' expected return can be calculated as:

$$k_2 = \left[\frac{[D_0 + \left[\frac{f}{1-f}\right] sB_0]}{P_0} \right] + g \qquad (4)$$

The reported secondary market price, for example, the price reported in the Wall Street Journal, does not include the brokerage fees paid by the purchaser in the secondary market. Thus, brokerage fees must be added to the observed market price to determine the full price paid by the purchaser. As a first approximation, it can be expected that these fees are a fixed proportion of the market value of the stock. Letting "c"

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[8] The term ($sB_0/1-f$) is the gross proceeds per current common share. Multiplying it by "f" gives the dollar value of the flotation costs. The measure itself is a transformation of the flotation cost measure developed by Arzac and Marcus (1981, 1201).

represent the brokerage fees as a proportion of the market price, equation (3) can be rewritten as:

$$P_0(1+c) = \int_0^\infty \left[\frac{[D_0 + \left[\frac{f}{1-f}\right] sB_0]\, e^{gt}}{e^{k_3 t}} \right] dt \qquad (5)$$

Solving (5) for k_3 yields:

$$k_3 = \frac{D_0}{P_0} \left[\frac{1 + d}{1 + c} \right] + g \qquad (6)$$

where $d = [f/(1-f)]\ s\ B_0/D_0$; that is, d is the expected issuance expense per outstanding share as a fraction of the current indicated dividend per share.

This estimate, k_3, is the most precise estimate of the investor's expected return. It takes into account both the flotation costs incurred by the firm and the brokerage fees paid by the investor. The value of k_3 will be greater than, equal to, or less than k_1 (the unadjusted estimate of the investor's expected return from equation (2) when:[9]

$$d \gtreqless c \qquad (7)$$

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[9] Equation (6) can be written as:

$$k_3 = \frac{D_0}{P_0} \left[\frac{1 + \frac{\left[\frac{f}{1-f}\right] sB_0}{D_0}}{1 + c} \right] + g$$

and the results in equation (7) follow directly.

The adjustment itself also makes intuitive sense. As can be seen from equation (8), buyer-paid transaction costs <u>ceteris paribus</u> reduce the stock price while recovery of firm-paid selling costs increases the stock price (and vice versa).

$$P_0 = \frac{\dfrac{D_0(1 + d)}{(1 + c)}}{k_3 - g} \qquad (8)$$

Empirical Application

The group of firms that provide the basis for the Standard and Poor's Electric Power Company Stock Price index is used to examine the magnitude of a complete transaction cost adjustment. All of the relevant information for these firms is available in various issues of Moody's <u>Public Utility Manual</u>. An estimate of the brokerage fees paid by purchasers in the secondary market is obtained from the SEC's "Commission Rate Trends, 1975-81."

Table 1 contains the transaction cost adjustment for each of the firms in the S & P Electric Power Company group for 1981, the last year for which SEC brokerage commission data is available. The obvious result is that the full transaction cost adjustment (Habr or H-adjustment) in column (7) is much smaller than the adjustment (column (8)) proposed by Patterson (1981, 1983) and Brigham et al. (1985), the Patterson, Brigham <u>et al</u>. or P-B adjustment).

The reason for this difference is two-fold. First (and most obvious), the H-adjustment takes into account the brokerage commissions paid by secondary market purchasers. The second, less obvious, reason is a result of the implicit assumption in the P-B adjustment that the aggregate amount of each year's new common equity issue is expected to equal the aggregate amount of common dividends paid.

This implicit assumption is made clear by analyzing equations (9) and (10) below. Equation (9) reflects the effects of the company-incurred flotation costs from the H-adjustment while equation (10) reflects the P-B adjustment.

$$\frac{D_0}{P_0}(1 + d) = \frac{D_0}{P_0}\left[1 + \frac{f}{1-f}(s)\frac{B_0}{D_0}\right] \qquad (9)$$

$$\frac{D_0}{P_0}(1/1\text{-}f) = \frac{D_0}{P_0}\left[1 + \frac{f}{1-f}\right] \qquad (10)$$

TABLE 1

ESTIMATION OF THE TRANSACTION COST ADJUSTMENT
USING DATA ENDING IN 1981

Company	Flotation Cost	Issuance Rate	Book Value Per Share*	Indicated Dividend*	1 + d	1 + c	H-Adjustment (1 + d)/ 1 + c	P-B Adjustment 1/1-f
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
American Electric Power	3.496%	2.600%	$20.58	$ 2.26	1.008577	1.008396	1.00018	1.03623
Baltimore Gas & Electric	3.493	2.201	30.75	2.68	1.009141	1.008396	1.00074	1.03619
Central and South West Corporation	3.012	3.672	17.59	1.58	1.012693	1.008396	1.00426	1.03106
Commonwealth Edison	3.824	1.709	26.69	2.80	1.006476	1.008396	.99810	1.03976
Consolidated Edison	3.592	0.797	23.73	1.48	1.004759	1.008396	.99639	1.03726
Detroit Edison	4.062	2.541	18.14	1.68	1.011615	1.008396	1.00319	1.04234
Dominion Resources	3.601	5.069	18.72	1.50	1.023635	1.008396	1.01511	1.03736
Duke Power	3.856	4.162	23.35	2.20	1.017719	1.008396	1.00925	1.04011
FLP Group	2.514	4.942	17.76	1.52	1.014888	1.008396	1.00644	1.02579
Middle South Utilities	3.119	4.973	17.74	1.66	1.017111	1.008396	1.00864	1.03219
Niagara Mohawk	4.118	3.200	17.40	1.64	1.014580	1.008396	1.00613	1.04295
Ohio Edison	3.655	3.766	16.12	1.76	1.013089	1.008396	1.00465	1.03794
Pacific Gas & Electric	3.311	0.803	15.08	1.36	1.003047	1.008396	.99470	1.03424
Philadelphia Electric	3.663	1.627	18.57	2.00	1.005743	1.008396	.99737	1.03802
Public Service Electric & Gas	3.026	3.820	26.99	2.44	1.013184	1.008396	1.00475	1.03120
Public Service of Indiana	3.335	3.660	24.87	2.60	1.012076	1.008396	1.00365	1.03450
Southern California Edison	2.789	4.241	16.05	1.62	1.012058	1.008396	1.00363	1.02869

TABLE 1 (continued)
Estimation of the Transaction Cost Adjustment
Using Data Ending in 1981

Company	Flotation Cost (1)	Issuance Rate (2)	Book Value Per Share* (3)	Indicated Dividend* (4)	1 + d (5)	1 + c (6)	H-Adjustment (1 + d)/ 1 + c (7)	P-B Adjustment 1/1-f (8)
Southern Company	3.115%	4.819%	16.54	$ 1.62	1.015815	1.008396	1.00736	1.03215
Texas Utilities	2.578	4.365	22.06	1.88	1.013551	1.008396	1.00511	1.02646
Average	3.377	3.314	20.46	1.91	1.012093	1.008396	1.00367	1.03497
Standard Deviation							(.00497)	(.00495)

* Book value and indicated dividend have been adjusted to reflect stock splits through June of 1985.

Equation (10) is simply a special case of equation (9) where it is assumed that the issuance rate times the book value-to-dividend ratio is equal to one. For this product to be one, the net proceeds, sB_0, must equal the dividend, D_0. This is equivalent to the previously noted assumption that expected aggregate amount of new common equity issued is equal to the expected aggregate payment of common dividends.

Another implication of these results is that regulatory bodies that do not make an allowance for either flotation costs or brokerage fees are not committing a major error. The average H-adjustment for the S & P electric companies is not significantly different from one, the value of the H-adjustment that has no impact on the dividend yield.

Although the size of the adjustments in Table 1 may seem relatively small, in effect the P-B adjustment is approximately 9.5 times larger than the H-adjustment. For Class A & B electric utilities, the use of the P-B adjustment in 1981 instead of the H-adjustment would have given the utilities the opportunity to annually collect approximately $780 million in additional revenues.[10]

Summary

The foregoing has demonstrated that it is possible to develop and estimate a market-based cost of common equity for public utilities that takes into account both the flotation costs paid by the firm when new shares are issued and the brokerage fees paid by purchases of the firm's shares in the secondary market. A major implication of this model (and the empirical results) is that the use of P-B type adjustment leads to significant errors and gives utilities the opportunity to collect large dollar amounts in extra revenues.

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[10] Based on a total rate base of approximately $260 billion, average 1981 S & P electric group dividend yield of 12.564 percent. an average common equity ratio of 38.1 percent, and a corporate income tax rate of 50 percent.

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2010 Valuation Yearbook

Market Results for
Stocks, Bonds, Bills, and Inflation
1926–2009

MORNINGSTAR®

Table 2-1: Total Returns, Income Returns, and Capital Appreciation of the Basic Asset Classes: Summary Statistics of Annual Returns

Series	Geometric Mean (%)	Arithmetic Mean (%)	Standard Deviation (%)	Serial Correlation
Large Company Stocks				
Total Returns	9.8	11.8	20.5	0.02
Income	4.1	4.1	1.5	0.90
Capital Appreciation	5.5	7.4	19.8	0.01
Ibbotson Small Company Stocks				
Total Returns	11.9	16.5	32.8	0.06
Mid-Cap Stocks*				
Total Returns	10.9	13.7	25.0	0.04
Income	3.9	4.0	1.7	0.90
Capital Appreciation	6.7	9.5	24.3	-0.05
Low-Cap Stocks*				
Total Returns	11.3	15.2	29.4	0.02
Income	3.6	3.6	2.0	0.89
Capital Appreciation	7.5	11.4	28.7	0.01
Micro-Cap Stocks*				
Total Returns	12.1	18.2	39.2	0.07
Income	2.5	2.5	1.7	0.91
Capital Appreciation	9.5	15.6	38.6	0.06
Long-Term Corporate Bonds				
Total Returns	5.9	6.2	8.3	0.08
Long-Term Government Bonds				
Total Returns	5.4	5.8	9.6	-0.12
Income	5.1	5.2	2.7	0.96
Capital Appreciation	0.1	0.4	8.4	-0.26
Intermediate-Term Government Bonds				
Total Returns	5.3	5.5	5.7	0.13
Income	4.7	4.7	2.9	0.96
Capital Appreciation	0.5	0.6	4.5	-0.18
Treasury Bills				
Total Returns	3.7	3.7	3.1	0.91
Inflation	3.0	3.1	4.2	0.64

Data from 1926–2009. Total return is equal to the sum of three component returns: income return, capital appreciation return, and reinvestment return.

*Source: Morningstar and CRSP. Calculated (or Derived) based on data from CRSP US Stock Database and CRSP US Indices Database ©2010 Center for Research in Security Prices (CRSP®), The University of Chicago Booth School of Business. Used with permission.

Annual Total Returns

Annual and monthly total returns for large company stocks, small company stocks, long-term corporate bonds, long-term government bonds, intermediate-term government bonds, Treasury bills, and inflation rates are for the full 84-year time period presented in Appendix B. Those tables can be used to compare the performance of each asset class on both a monthly and an annual basis.

Real Rates versus Nominal Rates

The cost of capital embodies a number of different concepts or elements of risk. Two of the most basic concepts in finance are real and nominal returns. The nominal return includes both the real return and the impact of inflation.

The *real* rate of interest represents the exchange rate between current and future purchasing power. An ir in the real rate indicates that the cost of currei sumption has risen in terms of future goods. It is t rate of interest that measures the opportunity c foregoing consumption.

The relationship between real rates and nominal rai be expressed in the following equation:

$$\text{Real} = \left[\frac{1+\text{Nominal}}{1+\text{Inflation}}\right] - 1$$

$$\text{Nominal} = \left[(1+\text{Real}) \times (1+\text{Inflation})\right] - 1$$

It is important to note that the conversion of nominal and real rates is not an additive process; rather, it is a geometric calculation. The arithmetic sum or difference is calculated by adding or subtracting one number from the other. As illustrated in the above equation, the *real rate* of return involves taking the geometric difference of the nominal rate of return and the rate of inflation. Conversely, the nominal rate of return can be determined by taking the geometric sum of the real rate of return and the rate of inflation. For example, if the real rate is 2.5 percent and the inflation rate is 5.0 percent, the nominal rate of interest is not 7.5 percent (2.5+5.0) but 7.625 percent, or $[(1.025)\times(1.05)-1]$. Similarly, if the nominal rate is 7.625 percent and the inflation rate is 2.5 percent, the real rate is not 5.125 percent (7.625−2.5) but 5.0 percent, $[(1.07625/1.025)-1]$.

Discount rates are most often expressed in nominal terms. That is, they usually have an inflation estimate included in them. Unless stated otherwise, the cost of capital data presented in this book are expressed in nominal terms.

The Market Benchmark and Firm Size

Although not restricted to include only the 500 largest companies, the S&P 500 is considered a large company index. The returns of the S&P 500 are capitalization weighted, which means that the weight of each stock in the index, for a given month, is proportionate to its market capitalization (price times number of shares outstanding) at the beginning of that month. The larger companies in the index therefore receive the majority of the weight. The use of the NYSE "Deciles 1–2" series results in an even purer large company index. Yet many valuation professionals are faced with valuing small companies, which historically have had different risk and return characteristics than large companies. If using a large stock index to calculate the equity risk premium, an adjustment is usually needed to account for the different risk and return characteristics of small stocks. This will be discussed further in Chapter 7 on the size premium.

The Risk-Free Asset

The equity risk premium can be calculated for a variety of time horizons when given the choice of risk-free asset to be used in the calculation. The *Stocks, Bonds, Bills, and Inflation Yearbook* provides equity risk premia calculations for short-, intermediate-, and long-term horizons. The short-, intermediate-, and long-horizon equity risk premia are calculated using the income return from a 30-day Treasury bill, a 5-year Treasury bond, and a 20-year Treasury bond, respectively.

Although the equity risk premia of several horizons are available, the long-horizon equity risk premium is preferable for use in most business-valuation settings, even if an investor has a shorter time horizon. Companies are entities that generally have no defined life span; when determining a company's value, it is important to use a long-term discount rate because the life of the company is assumed to be infinite. For this reason, it is appropriate in most cases to use the long-horizon equity risk premium for business valuation.

20-Year versus 30-Year Treasuries

Our methodology for estimating the long-horizon equity risk premium makes use of the income return on a 20-year Treasury bond; however, the Treasury currently does not issue a 20-year bond. The 30-year bond that the Treasury issued until recently is theoretically more correct due to the long-term nature of business valuation, yet Ibbotson Associates instead creates a series of returns using bonds on the market with approximately 20 years to maturity. The reason for the use of a 20-year maturity bond is that 30-year Treasury securities have only been issued over the relatively recent past, starting in February of 1977, and have since been discontinued by the Treasury.

Currently, the longest term security offered by the Treasury is 10 years. The same reason exists for why Ibbotson does not use the 10-year Treasury bond; that is, a long enough history of market data is not available for 10-year bonds. Ibbotson Associates has persisted in using a 20-year bond to keep the basis of the time series consistent.

Income Return

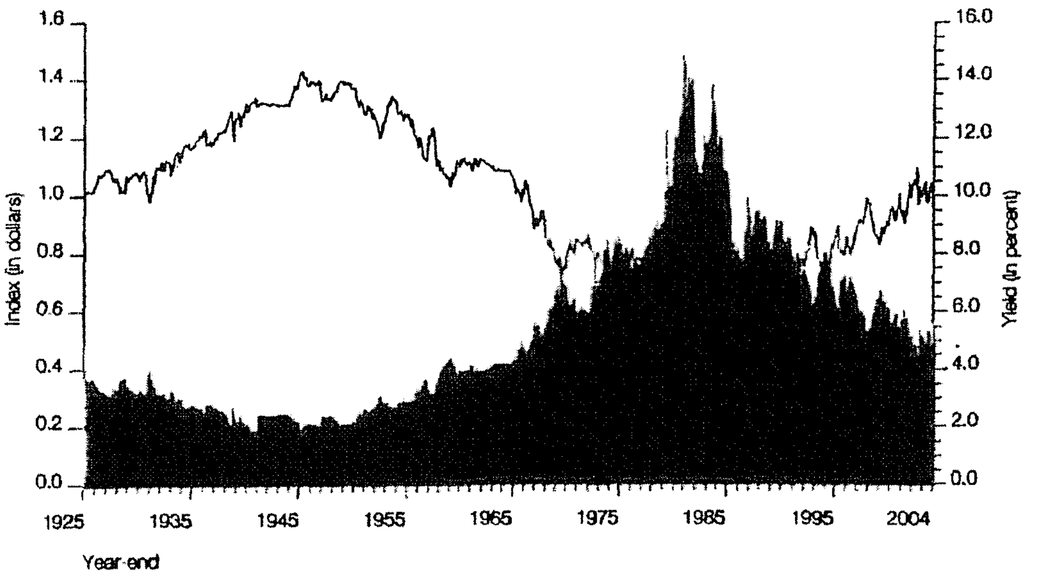
Another point to keep in mind when calculating the equity risk premium is that the income return on the appropriate-horizon Treasury security, rather than the total return, is used in the calculation. The total return is comprised of three return components: the income return, the capital appreciation return, and the reinvestment return. The income return is defined as the portion of the total return that results from a periodic cash flow or, in this case, the bond coupon payment. The capital appreciation return results from the price change of a bond over a specific period. Bond prices generally change in reaction to unexpected fluctuations in yields. Reinvestment return is the return on a given month's investment income when reinvested into the same asset class in the subsequent months of the year. The income return is thus used in the estimation of the equity risk premium because it represents the truly riskless portion of the return.[2]

Yields have generally risen on the long-term bond over the 1926–2004 period, so it has experienced negative capital appreciation over much of this time. Graph 5-2 illustrates the yields on the long-term government bond series compared to an index of the long-term government bond capital appreciation. In general, as yields rose, the capital appreciation index fell, and vice versa. Had an investor held the long-term bond to maturity, he would have realized the yield on the bond as the total return. However, in a constant maturity portfolio, such as those used to measure bond returns in this publication, bonds are sold before maturity (at a capital loss if the market yield has risen since the time of purchase). This negative return is associated with the risk of unanticipated yield changes.

Graph 5-2

Long-term Government Bond Yields versus Capital Appreciation Index

1925–2004



2 Please note that the appropriate forward-looking measure of the riskless rate is the yield to maturity on the appropriate-horizon government bond. This differs from the riskless rate used to measure the realized equity risk premium historically. Chapter 4 includes a thorough discussion of riskless rate selection in this context.

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Table of Contents

NOTE: See **Alphabetical Index** in front of this publication to find any particular company.
The reader's attention is called to the important explanatory information contained in the next few pages.

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Introduction

Mergent Public Utility Manual provides a wide reference source for public utility companies. The Manual offers broad coverage on over 338 electric and gas utilities, gas transmission companies, telephone and water companies. Many companies have Corporate Visibility - Ultra, Corporate Visibility - Plus or Corporate Visibility - Select Coverage providing a more detailed description of the company's operations and finances. Definitions of terms used in the Manual will be found following.

A Capital Structure Table follows the title of the companies receiving Corporate Visibility - Ultra, Corporate Visibility - Plus or Corporate Visibility - Select Coverage and gives highlights of outstanding bond and stock issues with Moody's® Bond and Preferred Stock Ratings. Following the Table are details of the history, background, mergers and acquisitions, subsidiaries, business, construction programs, principal plants and properties. Data relating to rates, franchises and contracts are also presented. Names and titles of officers and directors are shown as well as the general counsel, auditors, date of the annual meeting, number of stockholders and employees and the address of the corporation.

Financial statements are shown for all companies. In addition, a description of the capitalization of each company is shown. This includes information concerning a company's long-term debt and capital stocks as well as data on warrants and subscription rights.

The facts and figures selected for inclusion in the Manual are for the most part based upon information obtained directly from the corporations or from stockholders' reports, Federal Energy Regulatory Commission reports and Securities and Exchange Commission reports and registrations. However, in order to assure that the unique purposes of this Manual are realized, the manner and scope of the presentation of the information has been determined solely by Mergent. This Manual should not be viewed as a substitute for, but rather as a more readily accessible and convenient adjunct to, the information which, in respective companies which are subject to the reporting requirements of the Securities and Exchange Commission, may be obtained by reference to the materials filed with the Commission by such corporations.

We wish to acknowledge the cooperation received from the officers of the corporations covered, the Federal Energy Regulatory Commission and the Securities and Exchange Commission as well as various banking, brokerage and underwriting institutions.

In revising bond descriptions and stock descriptions of individual companies the objective has been to be specific and concise and editorial discretion has been used. Such descriptions are, of course, an abridgment and do not purport to represent a complete itemization of detail.

In the presentation of financial statements as well as other statistical material, editorial judgment has been exercised by combining or segregating items for the purpose of achieving clarity and/or uniformity. Also, attention is called to the fact that not all of the footnotes to the financial statements are shown and that those that are included are presented in condensed form.

In addition to the regular text, attention is called to the Special Features Section (blue paper insert) which contains, among other things, the following:

Convertible stocks and bonds, stock purchase warrants, and participating stocks.

Stock splits in 1999 and in 2000 to time of going to press.

Summary of Public Utility security issues sold in 1999.

Preferred stocks offering tax advantages to corporate holders.

Bonds maturing during next five years arranged chronologically, and all bonds classified according to Moody's® Ratings.

Non-callable bonds and preferred stocks.

Non-refundable bonds.

Bonds redeemed since last edition of the Manual.

Moody's® Public Utility Bond Yield Averages (by months) in each of four highest rating categories 1919 to date.

Moody's® Public Utility Preferred Stock Yield Averages by months from 1946 to date.

Moody's® Natural Gas Common Stock Averages.

MERGENT PUBLIC UTILITY NEWS REPORTS/CORPORATE NEWS REPORTS

Users of this Manual are directed to Mergent Corporate News Reports which are published on Tuesday of each week on the Mergent website (www.fisonline.com) and printed monthly. The News Reports contain data subsequent to the publication of Mergent Manual. Information contained therein includes interim financial statements, personnel changes, information on new plants or products, merger proposals, descriptions of new debt and stock issues, security offerings and announcements of new financings, etc. This edition of the Public Utility Manual covers information contained in the News Reports though September 2001.

MERGENT/MOODY'S® MANUALS ON MICROFICHE

Mergent/Moody's® Public Utility Manual was initiated in 1914. All superseded volumes are available on Moody's® Manuals on Microfiche - 1909 to Date - Series P. As each new Manual is published, Mergent plans to add it to the microfiche collection.

Definitions

RATIO POPULATION TO RESIDENTIAL CUSTOMERS

The general character of population estimates often makes the use of this ratio impracticable. Where available, however, it serves to indicate the extent to which the homes in the territory are electrified and the progress in this direction from year to year.

PERCENT RESIDENTIAL SALES AND REVENUES TO TOTAL

These ratios indicate the importance of this, the most stable source of revenue. Comparison can be made with corresponding ratios for the industry as a whole shown in the Blue Insert.

PERCENT INDUSTRIAL SALES AND REVENUES TO TOTAL

This ratio indicates the importance of this, the least stable source of revenue. Comparison can be made with corresponding ratios for the industry as a whole shown in the Blue Insert.

AVERAGE RATES

These figures provide a measure of the level of retail rates. In a given company the residential rates are the highest, commercial generally moderately lower, and industrial much lower. Comparisons between companies and with the industry as a whole provide indexes of the relative level of rates to each class of consumer but the average is determined not only by the actual rates but also by average usage, since the promotional schedules provide declining unit cost as consumption increases. There is a close correlation between the average rate and average usage, the former falls as the latter rises, (see below). Local factors are also important, i.e., in the case of electric service the cost of generation (availability of hydro power, cost of fuel), density of population, size of local industries, farm load including irrigation pumping, and in the case of gas, the cost of fuel, the availability and cost of natural gas, weather conditions, and consequently the size of the house heating load.

RESIDENTIAL AVERAGE CUSTOMER USE

This figure is computed by dividing residential sales by residential customers served. It indicates on the average the extent to which residential customers make use of the service. It is determined by the level of rates, the use of appliances, the operating cost of competitive equipment, the need of electricity for special local purposes, the purchasing power of the area and, of course, the extent to which a given company's sales policies affect these factors. The figures should be noted in conjunction with the residential average rate per sales unit - k.w.h., M c.f., etc.

DERIVATION OF EARNINGS

The percentage of net operating income and operating revenue derived from the sale of electricity, gas, transportation, etc., reveals the dependence of a given company on each service. A comparison of the percentages as applied to net operating income and operating revenue indicates the comparative profitableness of the different services and where data are available concerning the value of the property devoted to each service, the derivation of net operating income is of special interest.

PERCENT DEPRECIATION TO GROSS OPERATING REVENUES

Over a period of years this is a rough measure of the adequacy of depreciation or retirement appropriations, which bear a relation both to the utilization of the property (indicated by operating revenues) and to the value of the property, in turn related to operating revenues as indicated by the "Ratio of Depreciated Fixed Assets to Operating Revenue," defined below. Since it is often debatable whether certain property should be replaced from current maintenance or from accumulated pension for depreciation the "% Depreciation to Gross Operating Revenues" should be considered in conjunction with the "% Maintenance to Operating Revenues." These ratios must be used with caution and one must particularly avoid comparing those for companies whose properties are dissimilar, i.e., electric companies with steam generating plants, those with hydro-electric plants (which depreciate slowly), companies producing and distributing manufactured gas, those buying and distributing natural or mixed gas, telephone companies, telegraph companies and water companies.

PERCENT MAINTENANCE TO GROSS OPERATING REVENUES

Over a period of years this is also a rough index to be used both in conjunction with the "% Depreciation to Operating Revenues" in judging the adequacy of expenditures and appropriations for the preservation of the properties and independently to a limited extent in judging the condition of the properties.

PERCENT DEPRECIATION TO UTILITY PLANT (GROSS)

This is also an index of the adequacy of depreciation appropriations. Theoretically it is more accurate than the "% Depreciation to Operating Revenues" but it is often unreliable because the book value of different properties is determined by widely different principles. The note of caution to avoid comparisons between dissimilar properties cited above under "% Depreciation to Operating Revenues" is likewise applicable to this figure.

PERCENT NET OPERATING INCOME TO NET UTILITY PLANT

This figure indicates the realized rate of return on the book value of the properties without allowance for working capital and other elements such as going concern value not included in the property account. For these reasons and especially because the book value of different properties is determined by widely different principles, this ratio is of an approximate nature. However, it is useful in year to year comparisons for the same company and also between companies when allowances are made for the factors mentioned in the previous sentence.

OPERATING RATIO

This figure shown as a percentage throughout the Manual indicates the relation of operating expenses, maintenance, depreciation and taxes other than taxes on income as a total to gross operating revenues. The resulting operating ratio affords a measure for determining the efficiency with which the enterprise is conducted and while its value is greater in comparing the year to year trend it has a limited use in comparing very similar enterprises.

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION

"Allowance for funds used during construction" includes the net cost for the period of construction of borrowed funds used for construction purposes and a reasonable rate on other funds when so used.

It is noted that when a part only of a plant or project is placed in operation or is completed and ready for service but the construction work as a whole is incomplete, that part of the cost of the property placed in operation or ready for service, shall be treated as "Electric Plant in Service" and allowance for funds used during construction thereon as a charge to construction shall cease. Allowance for funds used during construction on that part of the cost of the plant which is incomplete may be continued as a charge to construction until such time as it is placed in operation or is ready for service.

TIMES CHARGES EARNED

"Times Charges Earned" is shown for operating companies and holding companies (parent company statement only) where the company has bonds or notes outstanding. This ratio indicates the relation between earnings (after depreciation or retirement expense) available for payment of all interest charges and debt discount and expense on the one hand and the aggregate amount of all these charges on the other hand. "Allowance for funds used during construction" and "allowance for borrowed funds used during construction" are included with other income as part of the company's earnings base and are not treated as a credit against interest requirements. "Other deductions" is not treated as an income deduction when making the computation but is charged as an expense and deducted from the amount available for charges. These figures are computed before and after deducting income taxes where such taxes are reported separately.

TIMES CHARGES AND PREFERRED DIVIDENDS EARNED OR OVER-ALL COVERAGE PREFERRED STOCK

This ratio is shown for operating companies and holding companies (parent company statements only) where the company has preferred shares outstanding.

It is computed in a manner similar to that used with respect to "Times Charges Earned" except that in all instances it is figured after income taxes, the comparison being between earnings as there defined on the one hand and preferred dividends plus fixed charges, the latter also as there defined, on the other.

TIMES OVER-ALL CHARGES EARNED

This calculation is made only on consolidated statements of holding companies and may be defined as the number of times that fixed charges and subsidiary preferred dividends (in the aggregate) were covered by total available earnings after depreciation, excluding in a certain few cases, profit on the sale of securities. Amortization of debt discount, etc. and rentals (wherever available) have been included in fixed charged, and where possible, minority interest has been deducted before arriving at the available balance. All special cases have been explained by footnotes.

"Over-all" ratios are in all cases preferable to so-called "times after" ratios, which are computed by applying the balance after all prior deductions to each layer of charges or dividends. Nevertheless, the "over-all" ratios are not an exclusive criterion and must be judged in the light of the individual company's sources of income, operating ratio, character of territory, franchise and governmental regulation situation, maintenance and depreciation policy, capital structure, current position, ability to transfer funds from foreign countries, rate of exchange used as a basis in compiling statements and other pertinent factors.

TIMES OVER-ALL CHARGES AND PREFERRED DIVIDENDS EARNED OR OVER-ALL COVERAGE PREFERRED STOCK

This calculation is similar to that described above, the comparison being made between available earnings on the one hand and the sum of fixed charges and subsidiary and parent company preferred dividends on the other hand.

EARNED PER SHARE

Earned per preferred share is based on the number of shares outstanding at the close of each year. In the case of a preferred stock on which there are no earnings available, we so indicate by the word "nil".

Earned per common share is generally shown as reported by the company in its annual report. Where shares outstanding have increased during the year, earnings per common share is usually based on the average number of shares outstanding during the year (in some cases including common equivalent shares). Earned per share based on common on a fully diluted basis, is shown when reported by company.

On some companies, Mergent has also computed the earnings per common share based on number of shares outstanding at end of year after allowance for the required dividends (whether or not such dividends were paid) on stock issues with a priority right as to dividends. Accumulations of unpaid dividends or payment of dividends with respect to accumulations in excess of the amount of annual requirements are ignored in the compiling of this figure. Where earnings are insufficient to cover requirements on stocks with a priority right or where there is a deficit and no senior stocks exist in the capital structure, we show "deficit" per common share.

NET TANGIBLE ASSETS PER SHARE - COMMON

This is the common stockholders' equity (common stock and surplus) less intangible assets, as shown on company's books, divided by the number of common shares. This calculation is simply a reflection of tangible book value applicable to common shares outstanding.

INTANGIBLE ASSETS

Such assets include "excess cost of acquisition" (excess of cost over equity in net assets of subsidiaries at dates of acquisition) or goodwill, patents, subscription lists, trademarks, etc.

ADJUSTED DATA FOR STOCK SPLITS AND STOCK DIVIDENDS

Earned per share - common, number of shares - common, net tangible assets per share - common and price ranges - common, have been adjusted for all stock splits and stock dividends.

PERCENT OF TOTAL CAPITALIZATION

These figures show how the capital structure is proportioned. A large percentage of preferred stock and common equity indicates a conservative structure. These data, however, are subject to all the reservations made under "% Debt to Depreciated Plant."

PERCENT DEBT TO DEPRECIATED PLANT

This computation reflects the extent to which the properties have been bonded, a low percentage indicating a conservative policy and, consequently, a stronger bond, while a high percentage indicates the converse. These conclusions, however, are subject to the reasonableness of the book value of the properties (see "Ratio Depreciated Fixed Assets to Operating Revenues") and to exceptions in the case of industries unable to earn a fair return on the value of their properties as determined by cost or physical appraisal. Furthermore, these ratios are not comparable among companies in different industries, some of which may conservatively be bonded to a greater extent than others.

RATIO GROSS PLANT TO GROSS OPERATING REVENUE

This is a rough measure of the reasonableness of the book value of a property and may be used in conjunction with the "% Depreciation to Gross Plant" to make allowances for the divergent principles of determining property values. The note of caution to avoid comparisons between dissimilar properties cited numbe. "% Depreciation to Gross Operating Revenues" is likewise applicable to this ratio.

PERCENT DEPRECIATION RESERVE OF PLANT

With reservations this ratio is a measure of the adequacy of depreciation policies in the past. It measures the extent to which provision has been made out of past earnings for future retirements of plant still in use. However, it must be judged in the light of the reasonableness of the plant account itself, the promptness with which property has been retired when it has reached the end of its useful life, and the character of the plant account.

ASSUMED

The word "assumed" as used in the Manual in regard to bonds means that the assuming company has entered into a legally binding agreement to pay principal and interest of the obligations.

NET CURRENT ASSETS - WORKING CAPITAL

Represents excess of total current assets over total current liabilities.

POOLING OF INTERESTS

A method of accounting used in mergers and acquisitions. In a pooling of interest, the two companies are treated, for accounting purposes, as if they had always been merged. Recognition isn't given to any excess of market value paid for acquired or merged company over its book value. The book values of assets of the two companies are simply added together, without regard for price paid for assets acquired.

EQUITY METHOD OF ACCOUNTING

A method of accounting whereby the equity in earnings or losses of affiliates, in which common stock is 20% to 50% owned, is reflected currently in earnings rather than when realized through dividends. Investments in such affiliates are reflected in balance sheet at cost plus equity in undistributed earnings since dates of acquisition, or at equity in underlying assets.

REDEEMABLE PREFERRED STOCKS

Effective for financial statements for fiscal periods ending on or after Sept. 15, 1979 the Securities & Exchange Commission adopted rules, encompassing certain amendments to Regulation S-X, to modify the financial statement presentation of preferred stocks subject to mandatory redemption requirements or whose redemption is outside the control of the issuer. Registrants having such securities outstanding are required to present separately, in balance sheets, amounts applicable to the following three general classes of securities: (i) Preferred stocks subject to mandatory redemption requirements or whose redemption is outside the control of the issuer; (ii) preferred stocks which are not redeemable or are redeemable solely at the option of the issuer; and (iii) common stocks. A general heading, stockholders' equity, is not to be used and presentation of a combined total for equity securities, inclusive of redeemable preferred stock, is prohibited. in addition, the rules required disclosure of redemption terms, five-year maturity data, and changes in redeemable preferred stocks in a separate note to the financial statements captioned "Redeemable Preferred Stocks."

MISCELLANEOUS

Gross Inc. % Long-Term Debt: Gross income (income before interest charges) plus Federal income taxes (including deferred) divided by long-term debt (including currently due portion).

Margin of Safety: Net income plus Federal income taxes (including deferred) divided by gross operating revenues.

Average annual yield: Dividend paid divided by the average price, i.e., high-low.

Average times earnings - Common: Average price (i.e. high-low) divided by common stock earnings (year end).

Fuel cost - % of revenue: Total fuel cost divided by gross operating revenues.

Labor cost - % of revenues: Total labor costs divided by gross operating revenues.

GENERAL

If a security is listed on a stock exchange that fact is included in the security description. Ticker symbols are shown for preferred and common stocks listed on the NYSE or ASE. "Traded: OTC" denotes that the stock is traded over-the-counter. NASDAQ Symbols are shown for stocks so traded.

Beginning with 1976, price ranges for stocks listed on the NYSE and ASE are composite ranges including trades on the Midwest, Pacific, Philadelphia, Boston and Cincinnati Stock Exchanges and trades reported by the National Association of Securities Dealers and Instinet.

Certain symbols are used in accounts to designate items as being credits or debits. The following are explanations of such symbols:

cr - used to indicate a credit item.

dr - used to indicate a debit item.

d - used to indicate a debit balance; also used to indicate a negative earned per share.

AVERAGE PRICE OF NEW CAPITAL

(Moody's Weighted Averages of Yields on Newly Issued Domestic Bonds and Preferred Stocks)

Year	Utility Preferred Stocks	Domestic Utility Bonds: Holding Cos	Light, Power, Gas	Telephone	Traction	Water Works	Other	[1]All Utility Bonds	[1]All Domestic Corporate Bonds
1922	7.09	6.64	6.02	5.27	6.31	5.96	6.65	6.02	6.28
1923	6.85	6.53	6.14	5.45	6.06	5.26	6.92	5.98	6.09
1924	6.97	6.46	5.90	5.51	6.49	5.73	6.30	6.03	5.96
1925	6.85	6.27	5.55	5.25	6.01	5.48	......	5.61	5.75
1926	6.77	6.06	5.40	5.01	6.08	5.40	5.00	5.50	5.61
1927	6.09	5.54	5.11	5.87	5.62	5.17	5.95	5.26	5.34
1928	5.80	5.37	5.01	5.16	5.42	5.18	5.14	5.20	5.24
1929	6.11	5.55	5.37	4.62	......	5.45	5.63	5.21	5.34
1930	6.08	5.46	5.11	5.03	5.82	5.22	5.00	5.20	5.17
1931	5.21	5.24	4.65	5.14	7.00	4.78	......	4.71	4.80
1932	6.90	8.00	5.66	7.58	6.24	6.42	5.84	5.74	5.73
1933	......	......	4.95	......	6.00	5.62	......	4.98	5.23
1934	......	4.38	4.81	4.50	6.15	5.08	......	4.86	5.03
1935	4.57	4.51	3.92	3.45	5.00	4.28	......	3.84	3.98
1936	4.66	4.13	3.56	3.19	4.50	3.86	......	3.55	3.67
1937	4.66	5.20	3.56	3.39	4.29	3.67	......	3.55	3.59
1938	4.88	......	3.49	3.13	......	4.99	3.50	3.46	3.48
1939	4.75	3.64	3.45	3.26	3.71	3.75	......	3.46	3.36
1940	4.49	3.00	3.09	2.94	......	3.65	......	3.08	3.10
1941	4.61	......	3.15	2.90	......	3.35	2.94	3.07	3.07
1942	4.84	......	3.35	2.87	......	3.44	......	3.26	3.22
1943	4.48	......	3.26	4.63	......	3.34	......	3.26	3.39
1944	4.20	......	2.97	2.91	3.85	......	......	2.98	3.09
1945	4.02	......	2.87	2.73	3.85	3.00	......	2.85	3.00
1946	3.63	......	2.74	2.72	......	2.66	......	2.73	2.75
1947	4.08	......	2.79	2.77	3.24	2.94	......	2.79	2.85
1948	4.60	......	3.07	3.09	4.45	3.85	......	3.09	3.20
1949	4.39	......	3.06	3.11	......	3.09	......	3.07	3.13
1950	4.23	......	2.86	2.73	......	3.22	3.75	2.85	2.94
1951	4.73	......	3.25	3.38	......	3.22	3.27	3.29	3.35
1952	4.71	......	3.36	3.44	......	......	3.27	3.38	3.42
1953	4.87	......	3.75	3.75	......	3.45	4.18	3.77	3.72
1954	4.34	......	3.11	3.09	......	3.41	3.45	3.17	3.22
1955	4.35	......	3.30	3.30	......	3.47	3.85	3.33	3.56
1956	4.65	......	3.86	3.78	......	4.04	......	3.86	3.88
1957	5.63	......	4.80	4.62	......	5.00	5.17	4.74	4.71
1958	5.04	......	4.18	4.19	......	4.80	5.06	4.21	4.26
1959	5.38	......	4.92	5.13	......	4.88	5.10	4.97	4.94
1960	5.43	......	4.72	4.76	......	5.47	5.33	4.84	4.82
1961	5.16	......	4.72	4.63	......	5.39	5.15	4.70	4.70
1962	4.63	......	4.40	4.55	......	4.89	4.77	4.44	4.46
1963	4.72	......	4.40	4.29	......	4.90	4.67	4.39	4.41
1964	4.74	......	4.55	4.55	......	4.61	......	4.56	4.54
1965	......	......	4.61	4.61	......	4.79	......	4.68	4.71
1966	5.37	......	5.53	5.51	......	5.02	......	5.61	5.59
1967	6.03	......	6.07	5.77	......	6.01	......	6.01	5.91
1968	6.44	......	6.80	6.55	......	7.17	......	6.72	6.70
1969	7.75	......	7.98	8.00	......	......	......	7.99	7.97
1970	9.01	......	8.79	8.72	......	......	......	8.85	8.85
1971	7.74	......	7.70	7.45	......	......	......	7.71	7.74
1972	7.53	......	7.50	7.11	......	......	......	7.46	7.47
1973	7.50	......	7.91	7.84	......	......	......	7.88	7.88
1974	9.95	......	9.59	9.21	......	......	......	9.21	9.08
1975	10.63	......	9.97	9.27	......	......	......	9.76	9.42
1976	9.12	......	8.92	8.41	......	......	......	8.80	8.72
1977	8.43	......	8.43	8.21	......	......	......	8.38	8.32
1978	9.03	......	9.30	9.07	......	......	......	9.22	9.17
1979	9.76	......	10.85	10.29	......	......	......	10.64	10.30
1980	12.28	......	13.46	12.59	......	......	......	13.09	12.60
1981	15.11	......	16.31	15.45	......	......	......	16.30	15.26
1982	14.42	......	14.93	14.23	......	......	......	14.56	14.23
1983	12.06	......	12.70	11.72	......	......	......	12.53	12.20
1984	13.16	......	14.25	12.73	......	......	......	13.33	13.05
1985	10.08	......	11.83	11.54	......	11.18	......	11.78	11.71
1986	8.26	......	9.61	8.96	......	......	......	9.45	9.42
1987	7.83	......	9.74	9.63	......	......	......	9.75	9.51
1988	7.38	......	10.03	10.05	......	10.15	......	10.19	0.02
1989	9.24	......	9.92	8.68	......	......	......	9.27	9.39
1990	9.34	......	9.82	9.70	......	......	......	9.83	9.86
1991	8.22	......	9.06	8.95	......	8.89	......	9.03	9.14
1992	7.36	......	8.12	7.67	......	8.08	......	8.04	8.44
[2]1993	......	......	......	......	......	......	......	......	......
1994	6.61	......	7.47	9.18	......	......	......	8.20	8.86
1995	......	......	7.82	7.33	......	7.87	......	7.75	7.80
1996	......	......	......	......	......	......	......	7.74	7.66
1997	......	......	......	......	......	......	......	7.63	7.53

[1]Beginning with 1957, based on bonds rated **Baa** or higher.
[2]Data for 1993 not available.

The above table shows the historial movement of the Cost of Capital for utility corporations in the United States. The "cost of capital" refers to the average yield to maturity on newly issued bonds, or the average current yield at which new preferred stocks are issued. The figures are weighted by the amounts of all new issues floated in any given classification or period.

The table gives a detailed comparison between various types of utility issues, and also a comparison of the average yield on all utility bonds with the average of yield on all domestic corporate bonds. Under "Holding Companies" are included light, power, gas, telephone and water works companies which are not directly engaged in operating, or only to a slight extent. Therefore, the classifications described as "Light, Power, Gas", "Telephone" and "Water Works" consist wholly of operating companies. Both operating and holding companies are included under the headings "Preferred Stocks", "Traction Bonds" and, "Other Bonds." Very few issues are included in the column headed "Other Bonds"; these consist of telegraph, toll bridge, ice, steam and other miscellaneous utility enterprises.

MOODY'S COMPOSITE AVERAGE OF YIELDS ON NEWLY ISSUED PUBLIC UTILITY BONDS (IN PERCENT)

Year	Jan.	Feb.	Mar.	Apr	May	Jun	Jul.	Aug	Sep	Oct	Nov	Dec
1998	6.16	6.39	6.57	6.52	6.67	6.32	6.91	6.36	......	......	......	......
1997	7.96		7.03	6.58	7.18	7.03	6.71	7.06	6.79	6.59	6.73	6.69
1996	6.85	......	7.69	7.92	7.72	8.00	8.03	7.31		7.35		7.19
1995	8.53	8.50	8.32	......	7.82	7.41	7.79	8.39	......	7.21	7.13	......
1994	7.30	7.31	7.53	8.15	8.33	8.28	8.38	8.26	8.60	8.71	9.51	......
1993	7.88	7.47	7.49	7.50	7.36	7.36	7.33	7.00	6.94	6.68	7.04	7.15
1992	8.21	8.43	8.67	8.58	8.43	8.38	8.15	7.78	7.92	8.46	8.17	7.96
1991	9.55	9.20	9.17	9.32	9.53	9.23	9.39	9.03	8.77	8.82	8.81	8.74
1990	9.85	9.92	9.95	10.04	10.27	9.84	9.78	10.05	10.69	10.79	9.81	8.61
1989	10.03	10.12	......	10.33	9.64	9.77	9.29	8.82	9.33	9.13	8.96	9.33

1988	10.25	9.76	10.02	10.29	10.82	10.02	10.46	10.14	10.75	9.84	10.12	10.05
1987	9.06	8.97	9.05	10.01	10.08	9.97	10.58	10.125	11.04	11.49	10.46	10.63
1986	10.87	9.60	9.17	9.00	9.63	9.64	9.54	9.32	10.53	9.78	9.29	9.11
1985	12.23	12.71	12.99	12.71	12.04	11.20	10.89	11.71	11.65	11.80	11.52	10.81
1984	12.94	14.50	13.57	13.70		15.43	16.00		13.53	12.96	12.61	15.25
1983	12.94	13.02	12.45	11.86	11.97	12.54	13.16	13.13	12.95	13.13	13.27	12.93
1982	18.16	16.81	17.07	16.15	16.16	16.39	16.20	15.90	14.90	13.35	12.41	13.11
1981	14.92	14.80	15.98	16.12	17.12	16.09	16.46		17.54	17.75	16.22	16.13
1980	12.09	14.26	15.04	13.23	11.81	11.80	12.06	12.74	13.66	13.87	14.00	14.25
1979	9.68	9.84	9.74	10.22	10.37	9.90	9.73	9.59	10.41	11.65	11.88	11.76
1978	9.05	9.21	9.01	9.08	9.40	9.30	9.62	8.80	8.90	9.38	9.47	9.29
1977	8.17	8.26	8.42	8.41	8.68	8.23	8.36	8.29	8.19	8.69	8.39	8.73
1976	9.06	8.96	8.84	8.60	9.32	9.16	9.38	8.58	8.57	8.53	8.44	8.23
1975	8.90	9.02	9.64	10.14	9.86	9.30	10.27	10.33	10.26	9.53	10.20	10.30
1974	8.36	8.16	8.66	9.08	9.23	9.60	10.41	10.12	10.39	10.74	9.61	9.65
1973	7.45	7.59	7.71	7.50	7.64	7.77	8.08	8.42	8.06	7.91	8.01	8.12
197.	7.16	7.45	7.52	7.64	7.45	7.47	7.49	7.50	7.63	7.55	7.18	7.41
1971	7.47	7.34	7.75	7.70	8.23	7.97	8.12	7.88	7.90	7.56	7.51	7.46
1970	8.76	8.67	8.73	8.84	9.05	9.36	8.94	9.10	8.87	9.07	8.75	8.07
1969	7.07	7.07	7.59	7.42	7.46	7.85	7.93	7.88	8.41	8.36	8.70	9.10
1968	6.41	6.40	6.72	6.79	6.97	6.87	6.62	6.47	6.49	6.81	6.98	7.17
1967	5.35	5.29	5.51	5.64	5.90	6.05	6.00	6.12	6.17	6.46	6.72	6.78
1966	4.97	5.11	5.29	5.27	5.40	5.53	5.74	5.85	5.97	5.97	5.94	6.08
1965	4.37	4.45	4.52	4.49	4.53	4.60	4.59	4.80	4.76	4.76	4.80	4.95
1964	4.59	4.62	4.54	4.58	4.55	4.55	4.49	4.59	4.52	4.64	4.55	4.50
1963	4.34	4.30	4.32	4.38	4.34	4.46	4.46	4.33	4.41	4.44	4.51	4.53
1962	4.54	4.59	4.41	4.61	4.30	4.42	4.43	4.38	4.54	4.31	4.32	4.33
1961	4.77	4.39	4.36	4.71	4.80	4.82	4.79	4.76	4.57	4.51	4.57	4.88
1960	5.09	5.02	4.83	4.97	5.10	5.00	4.83	4.49	4.65	4.73	4.83	4.86
1959	4.76	4.32	4.48	4.76	5.06	4.99	5.11	4.84	5.46	5.18	5.21	5.17

MOODY'S AVERAGE OF YIELD ON NEWLY ISSUED Aaa PUBLIC UTILITY BONDS (IN PERCENT)

Year	Jan.	Feb	Mar	Apr	May	Jun.	Jul.	Aug.	Sep.	Oct	Nov	Dec.
1998												
1997				6.58								
1996								7.31				
1995					7.80					7.06	7.02	6.47
1994	6.85					8.26	8.38		8.63			
1993	7.04	7.28		7.32		7.11	6.67	6.94		6.41		6.94
1992	7.99				8.10	8.34	8.00				7.74	7.88
1991										8.68		
1990												
1989							8.86	8.82		8.38	8.95	
1988	9.69	9.50		9.97								
1987		8.434										
1986		9.63		8.875				8.80		8.95		8.55
1985					11.54				11.50	11.50		
1984												
1983		12.25							12.36			
1982				16.11		15.95	16.00				11.701	
1981		14.80		15.68		15.36	15.98		16.94		16.62	15.91
1980	11.47	12.70	14.20	12.15	11.79	11.45	11.76	12.35	12.97	12.94		14.25
1979	9.37	9.59	9.65	9.58		9.37		9.53	10.00	10.73	10.93	
1978			8.72			8.90	9.10	8.75	8.63	9.12	9.16	9.27
1977	8.18	8.24	8.29	8.17	8.15	8.05			8.04		8.27	
1976	8.60	8.34	8.61	8.29		8.78		8.25	8.00	8.26	8.30	7.90
1975	8.625	8.73	9.23	9.20	9.00	9.07	8.80		9.68	9.40	9.375	9.35
1974	8.06	8.07	8.33	8.86	8.85	9.30	9.65	9.97	10.05	10.66		9.52
1973	7.36	7.30	7.625	7.43	7.625	7.71	8.06	8.20	7.91	7.79	8.05	8.00
1972	7.09	7.26		7.39	7.39	7.45	7.40	7.39	7.47	7.39	7.13	
1971	7.29	7.07	7.57	7.50	8.20	7.78	7.94	7.82	7.75	7.38	7.36	7.28
1970	8.64	8.59	8.59	7.77	8.91	8.96	8.53	8.705	8.56	8.86	8.55	7.60
1969	6.97	7.04	7.38	7.30	7.25	7.78	7.79	7.83	8.15	8.00	8.38	9.10
1968	6.28	6.32	6.59	6.70	6.72	6.74	6.51	6.25	6.34	6.59	6.83	6.92
1967	5.35	5.31	5.42	5.37	5.77	5.91	5.85	5.97	6.01	6.10	6.47	6.65
1966	4.83	4.97	5.12	5.12		5.40	5.69	5.58	5.95		5.96	5.79
1965	4.37				4.50	4.55	4.58		4.68	4.64	4.67	
1964	4.53			4.48	4.45		4.39					
1963	4.21	4.28	4.27		4.33	4.27	4.36	4.31				4.43
1962	4.50	4.52		4.23	4.27	4.30	4.39	4.39		4.30		
1961		4.32	4.32		4.64	4.68		4.60				
1960	5.03	5.01	4.88	4.80	4.80	4.78	4.75	4.54	4.54	4.66	4.72	4.78
1959		4.31	4.29	4.60				4.67	5.17	5.13		5.17

MOODY'S AVERAGE OF YIELD ON NEWLY ISSUED Aa PUBLIC UTILITY BONDS (IN FERCENT)

Year	Jan.	Feb	Mar	Apr	May	Jun	Jul	Aug.	Sep	Oct.	Nov	Dec.
1998	6.03	6.24	6.25		6.54	5.86						
1997						6.88	6.79			6.59	6.47	6.30
1996										7.35		7.05
1995		8.50				7.49		7.76	7.26	7.23	7.29	7.00
1994	7.08	7.21			8.15	8.07	8.26	8.26				
1993	7.79	7.18	7.34	7.17		7.48	7.36	6.85	7.12	6.74	6.79	7.05
1992	7.79	8.09	8.62	8.57	8.08	7.69	7.51	7.56	7.59	7.75	7.94	8.11
1991		9.06		9.23	9.18	9.36	8.78	8.89	8.74	8.55	8.70	8.30
1990	9.72			9.85	10.21	9.64	9.75				9.64	9.12
1989	10.00			9.93	9.63	9.06	9.37	8.84	9.29	8.65	8.18	9.20
1988		9.55	9.75	9.30	11.20		10.19			9.84		
1987	8.63	8.31		9.75	9.875	9.7		10.125		10.38	10.10	
1986	10.23	9.32	8.98	8.83	9.02	9.45	8.93	8.93	9.35	9.18	8.76	8.57
1985		12.375	13.06	12.80			10.41	11.73		11.60	11.34	10.62
1984			13.57	13.70					13.57	12.875	12.45	
1983		12.17	11.98	11.14	10.95						12.58	
1982			16.20	16.12	15.57	16.24	15.68		14.38	12.63	12.04	12.17
1981	14.86		15.23	16.35						17.75	15.80	15.85
1980	12.56	13.63	14.99	12.70	12.00	11.85		12.87	13.30	12.88	14.00	
1979	9.85		9.87		9.82	10.01	9.73	9.67		11.85	12.00	11.54
1978	8.97	8.80	8.75	9.04	9.01	9.41	9.57	8.86	8.95	9.55	9.54	9.31
1977	8.68	8.24	8.40	8.44		8.19	8.29	8.17	8.24	8.25	8.40	8.57
1976	8.95	8.65	8.83	8.73	9.05	9.00	8.70		8.43	8.41	8.30	8.22
1975	9.00	8.90	9.52	9.94	9.74	9.23	9.63	9.60	9.875	9.32	9.75	9.68
1974	8.37	8.13	8.61	9.98	9.20	9.46		10.75	10.45	11.33	9.15	9.61
1973	7.46	7.55	7.65	7.58	7.55	7.74	8.01	8.49	7.76	8.16	7.89	8.05
1972	7.11	7.49	7.39	7.60	7.42	7.45	7.53	7.43	7.58	7.51	7.17	7.30
1971	7.49	7.52	7.42	7.56	8.11	8.07	8.15	7.77	7.83	7.53	7.52	7.37
1970	8.66	8.49	8.62	8.76	9.06	9.32	8.94	8.72	8.83	8.90	8.70	7.87
1969	7.06	7.15	7.61	7.44	7.45	7.85	7.99	7.89	8.15	8.22	8.81	8.99
1968	6.43	6.47	6.73	6.90	6.82	6.85	6.79	6.47	6.42	6.79	6.83	7.11
1967	5.36	5.16	5.43	5.59	5.79	6.07	5.96	6.24	6.17	6.40	6.72	6.81
1966	4.90	5.12	5.35	5.21	5.31	5.65	5.77	6.10	5.90	5.84	5.74	5.93
1965		4.43	4.51	4.37	4.51	4.59	4.59	4.70	4.71	4.65	4.77	4.92
1964	4.35	4.38	4.50		4.46	4.48	4.42	4.42	4.50			4.50

1963	4.20	4.27	4.26	4.37	4.34	4.32	4.35	4.35	4.38	4.39	4.42	4.49
1962	4.55	4.51	4.41	4.29	4.24	4.26	4.42	4.34	4.27	4.26	4.24	4.32
1961	4.52	.....	4.37	4.61	4.59	4.76	4.65	4.85	4.50	4.45	4.48	4.69
1960	4.92	5.04	4.74	4.94	4.88	4.76	4.65	4.375	4.62	4.65	4.78	4.97
1959	4.59	4.35	4.43	4.59	5.03	4.98	4.93	4.93	5.48	5.12	5.21	5.16

MOODY'S AVERAGE OF YIELD ON NEWLY ISSUED A PUBLIC UTILITY BONDS (IN PERCENT)

Year	Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug	Sep.	Oct.	Nov.	Dec.
1998	6.15	6.43	.....	6.32	6.80	6.38	6.82	.....	.....	.....	.....	.....
1997	.....	.....	6.94	.....	7.18	6.50	6.63	7.00	6.79	.....	6.78	6.59
1996	6.85	.....	7.30	7.92	7.72	8.00	.....	.....	.....	.....	.....	7.43
1995	8.53	.....	8.32	.....	7.77	7.38	.....	.....	7 3	7.27	.....	.....
1994	7.07	7.34	7.46	8.07	.....	.....	8.48	.....	8.34	8.71	9.06	.....
1993	7.91	7.37	7.38	7.27	7.25	7.40	7.34	7.05	6.62	6.69	7.15	7.13
1992	7.95	8.47	8.69	7.93	8.57	8.64	8.47	7.83	7.95	8.11	8.45	7.84
1991	9.55	9.00	9.17	9.03	9.34	9.08	9.34	9.10	8.81	8.84	8.85	8.80
1990	.....	9.87	9.95	10.25	.....	9.73	9.60	.....	.....	.....	9.86	9.80
1989	10.07	10.12	.....	10.23	.....	.....	9.50	.....	9.24	9.32	9.87	9.47
1988	10.41	9.83	10.00	10.32	.....	10.12	10.52	10.22	.....	.....	9.80	9.93
1987	8.85	8.97	8.76	10.20	10.05	9.272	10.16	.....	10.90	11.00	10.30	.....
1986	10.76	9.76	9.26	9.11	9.36	9.81	9.55	9.59	9.95	9.52	9.36	9.19
1985	12.23	12.75	12.95	12.55	12.25	10.91	.....	11.70	12.04	11.876	11.28	10.84
1984	12.94	.....	.....	.....	.....	.....	.....	.....	.....	12.87	12.48	.....
1983	.....	12.94	12.27	11.63	11.85	12.06	12.91	12.88	13.01	13.02	13.16	12.93
1982	.....	16.81	16.71	16.26	15.43	16.56	.....	15.66	14.60	13.13	12.48	13.00
1981	15.00	.....	16.10	16.70	16.94	16.24	.....	.....	18.04	.....	15.86	16.01
1980	12.51	15.15	15.04	14.54	11.77	11.69	12.29	13.04	13.66	14.42	.....	.....
1979	9.95	9.95	.....	10.27	10.34	9.90	.....	9.88	10.36	12.04	12.49	12.25
1978	8.90	8.90	9.02	9.08	9.35	9.42	9.53	8.90	9.04	9.50	9.63	9.32
1977	8.38	8.39	8.51	8.67	8.68	8.34	8.60	8.25	8.35	8.52	8.56	8.64
1976	9.10	9.11	9.15	8.91	9.30	9.34	9.56	8.94	8.68	8.59	8.40	8.41
1975	9.71	9.42	10.16	10.94	10.00	9.87	10.38	10.76	10.83	10.46	10.11	10.31
1974	8.50	8.49	8.81	9.40	9.81	9.95	11.05	10.75	11.02	10.75	9.90	10.25
1973	7.54	7.68	7.69	7.66	7.68	7.87	8.21	8.76	8.18	8.38	8.10	8.21
1972	7.36	7.50	7.48	7.80	7.66	7.54	7.65	7.62	7.70	7.62	7.37	7.47
1971	7.90	7.74	8.09	7.89	8.39	8.08	8.42	7.88	8.19	7.75	7.74	7.61
1970	8.96	8.87	8.96	9.02	9.30	9.67	9.11	9.35	9.32	9.40	9.12	8.73
1969	7.17	7.37	7.85	7.41	7.64	7.92	8.07	8.02	8.71	8.56	8.95	9.16
1968	6.62	6.56	6.94	6.90	7.29	7.20	6.82	6.38	6.74	6.93	7.08	7.34
1967	.....	5.43	5.74	5.84	6.27	6.12	6.22	6.39	6.38	6.56	6.88	.....
1966	5.00	5.10	5.56	5.57	5.79	5.70	5.83	6.29	6.02	6.17	6.17	5.90
1965	.....	4.50	4.54	4.52	4.59	4.68	4.65	4.74	4.82	4.81	4.90	4.99
1964	4.55	4.44	4.55	4.61	4.61	4.57	.....	4.52	4.53	4.56	.....	.....
1963	4.325	4.32	4.33	4.43	4.38	4.40	4.40	.....	4.45	4.45	4.56	.....
1962	4.625	4.70	.....	4.35	4.33	4.47	4.43	4.51	4.35	4.42	4.32	.....
1961	.....	4.59	4.45	4.73	4.90	5.07	4.82	4.90	4.80	4.57	4.60	4.625
1960	5.30	5.10	4.98	5.14	5.15	5.18	4.74	.....	4.74	5.00	4.90	5.02
1959	4.72	.....	4.66	4.77	5.12	5.04	5.12	.....	5.65	5.29	.....	5.17

MOODY'S AVERAGE OF YIELD ON NEWLY ISSUED Baa PUBLIC UTILITY BONDS (IN PERCENT)

Year	Jan.	Feb.	Mar.	Apr	May	Jun	Jul.	Aug.	Sep	Oct.	Nov.	Dec.
1998	6.30	6.51	6.89	6.72	.....	6.72	6.99	6.36	.....	.....	.....	.....
1997	7.96	.....	7.12	.....	.....	7.44	7.25	7.18	.....	.....	6.93	7.19
1996	.....	.....	8.75	.....	.....	.....	8.03	.....	.....	.....	.....	.....
1995	.....	.....	.....	.....	7.95	.....	7.79	8.67	7.43	.....	7.19	.....
1994	7.52	7.29	7.89	8.34	8.57	8.57	.....	.....	.....	.....	9.77	.....
1993	8.67	7.97	7.84	7.86	7.56	7.21	7.42	7.11	7.27	6.94	.....	7.49
1992	8.69	8.91	.....	8.65	8.64	8.42	8.63	7.86	8.16	8.99	8.73	.....
1991	.....	9.59	.....	9.53	9.77	.....	9.78	9.39	8.65	9.21	8.82	9.07
1990	10.03	9.96	.....	10.33	10.30	10.01	10.25	10.05	10.69	10.74	9.99	7.70
1989	.....	.....	.....	10.75	9.65	9.93	9.86	.....	9.51	9.61	9.85	.....
1988	10.74	10.33	10.07	11.06	10.51	9.88	10.79	9.88	10.75	.....	10.30	10.21
1987	9.27	9.27	9.29	9.79	10.50	10.341	11.44	.....	11.14	12.06	10.95	10.63
1986	11.25	10.34	9.625	9.39	10.61	10.03	9.67	9.95	10.96	10.56	9.71	9.40
1985	.....	.....	.....	.....	11.81	11.50	12.00	.....	10.84	12.10	11.72	11.653
1984	.....	14.50	.....	.....	.....	15.43	16.00	.....	13.419	14.50	13.13	15.25
1983	12.94	13.33	13.02	12.41	12.58	13.28	13.75	13.45	13.13	13.50	13.59	.....
1982	18.16	.....	18.18	.....	16.98	.....	16.40	16.26	15.15	14.13	13.23	13.94
1981	15.00	.....	16.20	17.50	17.51	16.73	17.74	.....	18.75	.....	.....	18.14
1980	.....	.....	15.56	14.67	.....	12.38	13.625	13.88	15.02	14.67	.....	.....
1979	10.15	9.50	10.47	10.70	10.65	.....	.....	.....	10.99	.....	13.08	12.45
1978	9.35	9.45	9.53	9.42	9.69	10.00	9.88	.....	.....	9.75	.....	.....
1977	.....	.....	8.85	8.85	8.94	8.78	.....	8.59	.....	8.98	9.15	9.08
1976	9.90	9.60	9.50	9.61	10.00	9.92	10.10	.....	9.45	9.00	9.10	8.61
1975	.....	.....	.....	11.00	10.79	.....	11.57	.....	.....	.....	11.30	11.78
1974	8.95	8.70	9.07	9.53	9.45	.....	.....	.....	.....	.....	.....	.....
1973	7.625	.....	8.04	.....	7.97	8.20	8.25	.....	8.50	.....	.....	8.66
1972	.....	7.76	7.89	7.95	.....	7.95	.....	7.85	7.95	7.86	.....	.....
1971	8.12	7.90	8.47	8.49	8.76	8.94	.....	8.67	.....	7.97	7.91	8.10
1970	9.625	9.57	9.54	9.37	.....	10.47	9.53	10.08	9.81	9.82	9.75	8.95
1969	7.45			7.77	7.85	.....	8.52	.....	8.95	8.75	9.45	9.61
1968	6.81			.....	7.25	7.50	7.00	6.84	6.86	6.95	7.34	7.45
1967	.....	5.80	5.80	6.00		6.50	.....	6.50	6.63	6.75	.....	.....
1966	5.29	5.35	5.83			5.85	6.20	6.125	.....	6.50	6.29	6.38
1965							.....	4.94	4.96		4.95	.....
1964	4.81	4.97	.....	4.81	4.74	4.71	4.62	4.80	4.65	4.75	4.55	
1963	4.80	4.45	4.43			4.81	4.63		.....	4.54	.....	4.83
1962		5.17		4.82	4.52	4.97	4.63		4.90		4.50	4.48
1961	4.96			5.08	5.10	5.35	5.20	5.10			4.89	5.15
1960	5.67			5.33	5.45	5.61	5.40		5.08	5.03	5.04	
1959	5.10			4.92	5.25		5.15	5.05				

MOODY'S BOND YIELDS BY RATING GROUPS

MOODY'S COMPOSITE AVERAGE OF YIELDS ON PUBLIC UTILITY BONDS (IN PERCENT)

Year	Aver	Jan	Feb.	Mar.	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec.
2001		7.76	7.69	7.59	7.81	7.88	7.75						
2000	8.14	8.22	8.10	8.14	8.14	8.55	8.22	8.17	8.05	8.16	8.08	8.03	7.79
1999	7.55	6.87	7.00	7.18	7.16	7.42	7.70	7.66	7.86	7.87	8.02	7.86	8.04
1998	7.00	7.03	7.09	7.13	7.12	7.11	6.99	6.99	6.96	6.88	6.88	6.96	6.84
1997	7.63	7.79	7.68	7.92	8.08	7.94	7.77	7.52	7.57	7.51	7.37	7.25	7.16
1996	7.74	7.20	7.37	7.72	7.88	7.99	8.07	8.02	7.84	8.01	7.76	7.48	7.58
1995	7.91	8.77	8.56	8.41	8.30	7.93	7.71	7.73	7.86	7.62	7.46	7.40	7.21
1994	8.30	7.31	7.44	7.83	8.20	8.32	8.31	8.47	8.41	8.65	8.88	9.00	8.79
1993	7.56	8.23	8.00	7.85	7.76	7.78	7.68	7.53	7.21	7.01	7.00	7.30	7.33
1992	8.57	8.67	8.77	8.84	8.79	8.72	8.64	8.46	8.34	8.32	8.44	8.53	8.36
1991	9.21	9.56	9.31	9.39	9.30	9.29	9.44	9.40	9.16	9.03	8.99	8.93	8.76
1990	9.76	9.44	9.66	9.75	9.87	9.89	9.69	9.66	9.84	10.01	9.94	9.76	9.57
1989	9.66	10.02	10.02	10.16	10.14	9.92	9.49	9.34	9.37	9.43	9.37	9.33	9.31
1988	10.45	10.75	10.11	10.11	10.53	10.75	10.71	10.96	11.09	10.56	9.92	9.89	10.02

Year	Aver.	Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
1987	9.98	8.77	8.81	8.75	9.30	9.82	9.87	10.01	10.33	11.00	11.32	10.82	10.99
1986	9.46	10.66	10.16	9.33	9.02	9.52	9.51	9.19	9.15	9.42	9.39	9.15	8.96
1985	12.29	12.88	13.00	13.66	13.42	12.89	11.91	11.88	11.93	11.95	11.84	11.33	10.82
1984	14.03	13.40	13.50	14.03	14.30	14.95	15.16	14.92	14.29	14.04	13.68	13.15	12.96
1983	13.31	13.46	13.60	13.28	13.03	13.00	13.17	13.28	13.50	13.35	13.19	13.33	13.48
1982	15.33	16.73	16.72	16.07	15.82	15.60	16.18	16.04	15.22	14.56	13.88	13.58	13.55
1981	15.62	14.22	14.84	14.86	15.32	15.84	15.27	15.87	16.33	16.89	16.76	15.50	15.77
1980	13.15	12.12	13.48	14.33	13.50	12.17	11.87	12.12	12.82	13.29	13.53	14.07	14.48
1979	10.39	9.85	9.84	10.02	10.05	10.23	10.04	9.90	9.97	10.19	11.13	11.73	11.68
1978	9.22	8.87	8.90	8.93	9.05	9.19	9.33	9.38	9.21	9.17	9.37	9.58	9.67
1977	8.58	8.59	8.63	8.66	8.65	8.64	8.53	8.48	8.47	8.43	8.56	8.61	8.65
1976	9.17	9.68	9.50	9.43	9.27	9.31	9.36	9.26	9.07	8.91	8.83	8.77	8.61
1975	9.88	10.10	9.83	9.67	9.88	9.93	9.81	9.81	9.93	9.98	9.94	9.83	9.87
1974	9.27	8.27	8.33	8.44	8.68	8.86	9.08	9.35	9.70	10.11	10.31	10.12	10.02
1973	7.83	7.51	7.61	7.64	7.64	7.63	7.69	7.81	8.06	8.09	8.04	8.11	8.17
1972	7.74	7.85	7.84	7.81	7.87	7.88	7.83	7.80	7.69	7.63	7.63	7.55	7.48
1971	8.13	8.17	7.94	8.08	8.05	8.23	8.39	8.34	8.30	8.12	8.04	7.96	7.92
1970	8.68	8.54	8.47	8.34	8.37	8.72	9.06	9.01	8.83	8.80	8.74	8.77	8.45
1969	7.49	7.02	7.05	7.23	7.26	7.15	7.38	7.49	7.40	7.62	7.91	7.94	8.39
1968	6.49	6.47	6.36	6.39	6.54	6.60	6.60	6.53	6.30	6.27	6.39	6.58	6.85
1967	5.81	5.42	5.25	5.37	5.37	5.59	5.80	5.91	5.96	6.02	6.12	6.39	6.57
1966	5.36	4.85	4.90	5.08	5.21	5.23	5.32	5.39	5.54	5.78	5.72	5.64	5.65
1965	4.60	4.52	4.51	4.51	4.51	4.53	4.56	4.58	4.60	4.64	4.67	4.71	4.82
1964	4.53	4.51	4.51	4.51	4.53	4.53	4.55	4.54	4.54	4.53	4.52	4.53	4.54
1963	4.41	4.38	4.37	4.38	4.39	4.39	4.40	4.42	4.42	4.44	4.44	4.45	4.49
1962	4.51	4.61	4.62	4.60	4.56	4.50	4.47	4.48	4.50	4.49	4.46	4.42	4.41
1961	4.57	4.57	4.51	4.43	4.46	4.49	4.52	4.60	4.67	4.67	4.66	4.63	4.62
1960	4.69	4.92	4.89	4.79	4.70	4.76	4.75	4.71	4.53	4.48	4.56	4.56	4.58
1959	4.70	4.43	4.46	4.43	4.49	4.67	4.77	4.79	4.77	4.89	4.95	4.86	4.86
1958	4.10	3.99	3.87	3.95	3.90	3.89	3.88	3.94	4.16	4.41	4.46	4.40	4.39
1957	4.18	3.98	3.97	3.95	3.94	3.98	4.06	4.19	4.33	4.45	4.48	4.49	4.29
1956	3.54	3.28	3.26	3.27	3.38	3.44	3.44	3.48	3.60	3.73	3.82	3.86	3.93
1955	3.22	3.12	3.15	3.17	3.17	3.19	3.21	3.22	3.26	3.29	3.27	3.28	3.31
1954	3.15	3.31	3.23	3.14	3.13	3.13	3.15	3.13	3.12	3.13	3.11	3.10	3.10
1953	3.45	3.23	3.29	3.33	3.44	3.57	3.62	3.56	3.54	3.58	3.46	3.38	3.37
1952	3.20	3.23	3.19	3.21	3.19	3.19	3.20	3.20	3.20	3.20	3.22	3.19	3.19
1951	3.09	2.85	2.86	2.96	3.07	3.10	3.18	3.19	3.13	3.09	3.14	3.21	3.24
1950	2.82	2.79	2.78	2.78	2.79	2.81	2.81	2.83	2.80	2.84	2.85	2.86	2.87
1949	2.90	2.99	2.99	2.97	2.96	2.95	2.93	2.89	2.86	2.84	2.83	2.81	2.79
1948	3.03	3.03	3.03	3.01	2.97	2.95	2.96	3.02	3.07	3.07	3.07	3.09	3.06
1947	2.78	2.73	2.72	2.73	2.71	2.71	2.72	2.72	2.72	2.78	2.87	2.93	3.02
1946	2.71	2.71	2.65	2.64	2.65	2.69	2.70	2.69	2.70	2.75	2.76	2.77	2.77
1945	2.89	2.97	2.95	2.94	2.94	2.93	2.89	2.87	2.86	2.85	2.84	2.81	2.79
1944	2.97	2.99	2.98	2.97	2.97	2.97	2.96	2.95	2.94	2.94	2.96	2.98	2.96
1943	2.99	3.05	3.02	3.00	3.01	3.00	2.98	2.95	2.96	2.96	2.96	2.98	3.00
1942	3.11	3.13	3.15	3.17	3.13	3.13	3.12	3.09	3.09	3.08	3.07	3.06	3.07
1941	3.11	3.17	3.19	3.17	3.16	3.13	3.10	3.07	3.06	3.07	3.05	3.04	3.12
1940	3.25	3.35	3.33	3.29	3.24	3.30	3.33	3.23	3.23	3.19	3.18	3.14	3.13
1939	3.48	3.57	3.52	3.48	3.51	3.45	3.42	3.39	3.40	3.70	3.57	3.41	3.38
1938	3.87	4.01	4.07	4.05	4.11	3.90	3.90	3.79	3.76	3.82	3.73	3.65	3.63
1937	3.93	3.68	3.76	3.90	3.99	3.95	3.97	3.92	3.89	3.96	4.08	4.06	4.03
1936	3.88	4.02	3.98	3.98	3.97	3.95	3.91	3.86	3.85	3.83	3.80	3.74	3.69
1935	4.43	4.97	4.76	4.65	4.60	4.43	4.37	4.26	4.28	4.27	4.24	4.17	4.12
1934	5.40	6.24	5.58	5.50	5.31	5.27	5.24	5.23	5.37	5.43	5.30	5.22	5.15
1933	6.25	5.56	5.90	6.41	6.82	6.34	5.99	5.78	5.90	6.31	6.38	6.82	6.82
1932	6.30	6.20	6.36	6.10	6.66	6.98	7.21	6.97	6.03	5.69	5.72	5.84	5.80
1931	5.27	5.09	5.09	4.99	4.97	4.97	5.04	5.00	..01	5.24	5.79	5.72	6.31
1930	5.05	5.17	5.20	5.10	5.08	5.04	5.03	5.00	4.94	4.87	4.93	5.05	5.21
1929	5.14	4.96	5.00	5.07	5.09	5.09	5.15	5.16	5.22	5.27	5.25	5.24	5.17
1928	4.87	4.79	4.77	4.75	4.75	4.79	4.90	4.93	4.97	4.96	4.93	4.90	4.95
1927	4.96	5.02	5.05	5.03	4.98	4.99	4.98	4.98	4.94	4.92	4.89	4.88	4.84
1926	5.11	5.20	5.15	5.17	5.12	5.08	5.06	5.08	5.09	5.10	5.11	5.07	5.05
1925	5.29	5.44	5.41	5.39	5.35	5.22	5.20	5.25	5.28	5.26	5.24	5.24	5.25
1924	5.61	5.82	5.77	5.76	5.74	5.67	5.59	5.52	5.51	5.52	5.48	5.49	5.46
1923	5.84	5.72	5.73	5.90	5.93	5.88	5.89	5.89	5.77	5.85	5.85	5.85	5.86
1922	5.93	6.40	6.31	6.20	6.05	5.87	5.87	5.83	5.78	5.68	5.67	5.77	5.76
1921	7.17	7.43	7.35	7.35	7.34	7.38	7.41	7.42	7.34	7.08	6.95	6.58	6.37
1920	7.19	6.63	6.76	6.83	7.03	7.30	7.35	7.37	7.48	7.40	7.28	7.31	7.49
1919	6.21	6.08	6.11	6.14	6.09	6.08	6.08	6.10	6.19	6.30	6.28	6.43	6.58

MOODY'S AVERAGE OF YIELDS ON Aaa PUBLIC UTILITY BONDS (IN PERCENT)

Year	Aver	Jan	Feb	Mar.	Apr.	May	Jun.	Jul.	Aug	Sep	Oct.	Nov	Dec.
2001		7.53	7.46	7.31	7.53	7.61	7.50	...	...	...	...	...	...
2000	7.88	7.95	7.82	7.87	7.87	8.22	7.96	8.00	7.89	7.92	7.80	7.71	7.51
1999	7.21	6.41	6.56	6.78	6.80	7.09	7.37	7.34	7.54	7.55	7.73	7.56	7.74
1998	6.77	6.85	6.91	6.96	6.94	6.94	6.80	6.80	6.75	6.66	6.63	6.59	6.43
1997	7.42	7.53	7.43	7.70	7.87	7.72	7.55	7.29	7.39	7.33	7.18	7.09	6.99
1996	7.49	6.92	7.11	7.45	7.60	7.73	7.83	7.78	7.59	7.76	7.50	7.21	7.33
1995	7.68	8.53	8.33	8.18	8.08	7.71	7.39	7.51	7.66	7.42	7.23	7.13	6.94
1994	8.07	7.05	7.19	7.60	8.00	8.11	8.07	8.21	8.15	8.41	8.65	8.77	8.55
1993	7.29	7.94	7.75	7.64	7.50	7.44	7.37	7.25	6.94	6.76	6.77	7.06	7.07
1992	8.19	8.22	8.30	8.39	8.36	8.32	8.26	8.12	8.04	8.04	8.06	8.11	8.01
1991	8.85	9.17	8.92	9.04	8.95	8.93	9.10	9.10	8.81	8.65	8.57	8.52	8.38
1990	9.45>	9.08	9.35	9.48	9.60	9.58	9.38	9.36	9.54	9.73	9.66	9.43	9.18
1989	9.32	9.72	9.71	9.87	9.88	9.60	9.13	8.98	9.02	9.10	9.01	8.92	8.92
1988	10.05	10.39	9.77	9.72	10.07	10.29	10.27	10.50	10.66	10.15	9.61	9.52	9.67>
1987	9.52	8.23	8.29	8.21	8.83	9.34	9.37	9.56	9.92	10.53	10.92	10.43	10.64
1986	8.92	10.14	9.65	8.75	8.45	9.07	9.02	8.66	8.59	8.91	8.84	8.59	8.41
1985	11.68	12.47	12.61	13.08	12.77	12.18	11.17	11.18	11.23	11.27	11.23	10.71	10.24
1984	12.72	...	...	...	...	...	...	...	...	...	13.00	12.66	12.49
1983	12.52	12.29	12.48	12.19	12.00	12.01	12.23	12.69	13.04	12.85	12.66	12.82	13.00
1982	14.22	15.79	15.88	15.05	14.86	14.68	15.32	14.96	13.98	13.24	12.42	12.11	12.32
1981	14.64	13.31	13.95	13.85	14.41	14.83	14.16	14.87	15.41	16.06	15.83	14.43	14.52
1980	12.30	11.33	12.75	13.33	12.27	11.23	10.88	11.48	12.10	12.46	12.79	13.39	13.62
1979	9.86	9.48	9.51	9.61	9.61	9.71	9.49	9.42	9.46	9.69	10.38	10.99	10.96
1978	8.87	8.52	8.57	8.57	8.69	8.83	8.92	9.02	8.86	8.84	9.04	9.19	9.34
1977	8.19	8.14	8.21	8.27	8.21	8.22	8.12	8.10	8.13	8.07	8.18	8.23	8.34
1976	8.63	8.86	8.80	8.74	8.59	8.73	8.84	8.78	8.64	8.57	8.50	8.39	8.15
1975	9.03	8.99	8.79	8.82	9.11	9.05	8.93	9.04	9.20	9.21	9.14	9.03	9.07
1974	8.71	8.00	8.01	8.14	8.36	8.48	8.58	8.83	9.09	9.36	9.50	9.10	9.02
1973	7.60	7.33	7.41	7.45	7.44	7.44	7.51	7.62	7.81	7.78	7.77	7.83	7.86
1972	7.46	7.48	7.53	7.54	7.59	7.61	7.53	7.43	7.41	7.41	7.40	7.30	7.26
1971	7.72	7.70	7.49	7.62	7.59	7.86	8.01	7.96	7.89	7.74	7.69	7.55	7.54
1970	8.31	8.07	8.12	8.07	8.08	8.45	8.79	8.68	8.42	8.39	8.30	8.34	7.97
1969	7.12	6.70	6.78	6.97	6.96	6.88	7.08	7.11	6.99	7.24	7.44	7.48	7.86
1968	6.22	6.24	6.13	6.13	6.26	6.31	6.32	6.28	6.07	6.03	6.14	6.25	6.52
1967	5.58	5.17	5.01	5.16	5.14	5.33	5.55	5.70	5.76	5.82	5.89	6.16	6.30
1966	5.19	4.76	4.82	4.98	5.08	5.10	5.17	5.22	5.34	5.56	5.50	5.40	5.39
1965	4.50	4.41	4.42	4.43	4.42	4.45	4.47	4.48	4.50	4.54	4.57	4.61	4.72
1964	4.42	4.40	4.38	4.39	4.41	4.42	4.44	4.43	4.43	4.43	4.42	4.43	4.44
1963	4.27	4.19	4.19	4.20	4.21	4.23	4.25	4.29	4.31	4.33	4.33	4.34	4.37
1962	4.35	4.44	4.45	4.42	4.38	4.34	4.32	4.35	4.36	4.35	4.30	4.25	4.22
1961	4.37	4.35	4.29	4.23	4.28	4.29	4.31	4.41	4.48	4.47	4.46	4.41	4.44
1960	4.47	4.68	4.63	4.54	4.50	4.54	4.54	4.48	4.31	4.29	4.37	4.36	4.38
1959	4.49	4.23	4.25	4.24	4.31	4.48	4.56	4.60	4.54	4.62	4.74	4.66	4.65
1958	3.87	3.68	3.62	3.67	3.66	3.63	3.64	3.74	3.94	4.17	4.25	4.22	4.19
1957	3.96	3.81	3.74	3.71	3.71	3.72	3.89	4.05	4.21	4.26	4.25	4.22	3.93
1956	3.39	3.14	3.10	3.11	3.23	3.30	3.29	3.30	3.44	3.58	3.63	3.72	3.79
1955	3.09	2.95	3.01	3.05	3.03	3.07	3.08	3.09	3.15	3.19	3.14	3.13	3.17
1954	2.93	3.07	2.96	2.87	2.87	2.90	2.92	2.92	2.90	2.94	2.92	2.92	2.93
1953	3.24	3.05	3.13	3.18	3.30	3.40	3.41	3.32	3.30	3.35	3.20	3.12	3.15
1952	2.99	3.01	2.96	2.99	2.96	2.96	2.97	3.00	3.00	3.00	3.04	3.00	2.99
1951	2.88	2.65	2.67	2.80	2.89	2.91	2.99	2.97	2.90	2.87	2.92	3.00	3.03
1950	2.62	2.56	2.56	2.57	2.59	2.61	2.62	2.64	2.61	2.65	2.66	2.66	2.67

Year	Aver.	Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
1949	2.67	2.73	2.72	2.71	2.72	2.72	2.71	2.67	2.62	2.61	2.61	2.58	2.58
1948	2.81	2.82	2.82	2.81	2.75	2.74	2.75	2.82	2.87	2.85	2.85	2.85	2.81
1947	2.59	2.54	2.54	2.55	2.52	2.52	2.52	2.53	2.53	2.58	2.67	2.74	2.82
1946	2.51	2.51	2.44	2.44	2.45	2.49	2.48	2.48	2.50	2.55	2.58	2.58	2.60
1945	2.62	2.65	2.64	2.62	2.61	2.63	2.60	2.61	2.63	2.61	2.60	2.60	2.60
1944	2.65	2.67	2.66	2.65	2.64	2.64	2.63	2.62	2.63	2.65	2.66	2.68	2.66
1943	2.65	2.70	2.67	2.67	2.66	2.66	2.63	2.61	2.62	2.64	2.63	2.64	2.68
1942	2.73	2.74	2.77	2.79	2.75	2.75	2.74	2.72	2.72	2.71	2.71	2.69	2.71
1941	2.69	2.77	2.76	2.74	2.75	2.72	2.69	2.65	2.64	2.65	2.63	2.62	2.71
1940	2.77	2.81	2.80	2.76	2.75	2.82	2.85	2.78	2.79	2.74	2.74	2.72	2.72
1939	2.88	2.87	2.87	2.86	2.87	2.83	2.83	2.80	2.83	3.14	3.02	2.87	2.82
1938	3.03	3.10	3.09	3.08	3.10	3.03	3.02	3.01	3.01	3.02	2.98	2.94	2.92
1937	3.21	3.07	3.16	3.29	3.33	3.28	3.25	3.22	3.20	3.21	3.21	3.15	3.11
1936	3.21	3.30	3.26	3.28	3.26	3.23	3.21	3.19	3.20	3.18	3.16	3.13	3.07
1935	3.52	3.69	3.61	3.55	3.55	3.56	3.53	3.47	3.51	3.51	3.48	3.41	3.36
1934	3.92	4.25	4.10	4.03	3.97	3.93	3.85	3.81	3.83	3.87	3.82	3.78	3.74
1933	4.29	4.10	4.17	4.38	4.48	4.41	4.29	4.20	4.14	4.20	4.21	4.46	4.45
1932	4.61	4.92	5.00	4.68	4.70	4.71	4.83	4.76	4.57	4.39	4.32	4.30	4.18
1931	4.36	4.33	4.34	4.30	4.27	4.21	4.21	4.22	4.19	4.27	4.62	4.59	4.81
1930	4.50	4.62	4.66	4.60	4.58	4.58	4.54	4.49	4.43	4.37	4.36	4.38	4.43
1929	4.67	4.55	4.58	4.63	4.63	4.66	4.73	4.70	4.74	4.74	4.73	4.71	4.62
1928	4.51	4.47	4.44	4.43	4.42	4.45	4.53	4.56	4.59	4.54	4.55	4.53	4.56
1927	4.59	4.65	4.66	4.63	4.59	4.61	4.58	4.62	4.57	4.55	4.54	4.53	4.49
1926	4.70	4.78	4.70	4.73	4.66	4.64	4.67	4.68	4.69	4.72	4.74	4.70	4.69
1925	4.82	4.89	4.91	4.86	4.84	4.80	4.74	4.81	4.83	4.79	4.77	4.76	4.80
1924	4.96	5.09	5.04	5.03	5.05	5.00	4.95	4.91	4.88	4.89	4.85	4.90	4.89
1923	5.14	5.09	5.08	5.22	5.31	5.22	5.17	5.13	5.06	5.13	5.11	5.11	5.10
1922	5.23	5.59	5.49	5.37	5.30	5.23	5.14	5.15	5.09	5.03	5.01	5.19	5.11
1921	6.34	6.68	6.58	6.54	6.49	6.56	6.59	6.56	6.35	6.24	5.99	5.81	5.72
1920	6.53	6.13	6.21	6.22	6.35	6.55	6.79	6.77	6.82	6.72	6.50	6.53	6.78
1919	5.68	5.45	5.45	5.51	5.55	5.49	5.57	5.64	5.82	5.86	5.78	5.95	6.10

[1] The Aaa public utility average was suspended January 17, 1984, because of a lack of appropriate issues. [2] The Aaa utility average was reinstated on October 12. The 1984 high and low for the Average Utility and the Aaa Utility, were determined when a Aaa Utility was available.

MOODY'S AVERAGE OF YIELDS ON Aa PUBLIC UTILITY BONDS (IN PERCENT)

Year	Aver.	Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul	Aug.	Sep.	Oct.	Nov.	Dec.
2001	....	7.73	7.62	7.51	7.72	7.79	7.62	....	....	....	....	....	....
2000	8.06	8.17	7.99	7.99	8.00	8.44	8.10	8.10	7.95	8.11	8.08	8.03	7.79
1999	7.51	6.82	6.94	7.11	7.11	7.38	7.67	7.62	7.82	7.82	7.96	7.82	8.00
1998	6.91	6.94	6.99	7.04	7.02	7.02	6.91	6.91	6.87	6.78	6.79	6.89	6.78
1997	7.54	7.68	7.60	7.84	8.00	7.85	7.68	7.43	7.46	7.43	7.28	7.15	7.07
1996	7.57	7.02	7.20	7.55	7.70	7.79	7.87	7.83	7.66	7.84	7.60	7.32	7.44
1995	7.77	8.66	8.45	8.29	8.17	7.80	7.49	7.60	7.71	7.48	7.30	7.22	7.03
1994	8.21	7.18	7.34	7.74	8.12	8.24	8.21	8.38	8.32	8.56	8.78	8.90	8.69
1993	7.44	8.14	7.92	7.76	7.64	7.64	7.54	7.38	7.07	6.89	6.91	7.17	7.18
1992	8.55	8.63	8.76	8.82	8.76	8.69	8.63	8.45	8.30	8.28	8.42	8.51	8.32
1991	9.09	9.39	9.16	9.23	9.14	9.16	9.28	9.26	9.06	8.95	8.92	8.87	8.71
1990	9.65	9.39	9.57	9.60	9.81	9.83	9.60	9.61	9.78	9.87	9.77	9.59	9.42
1989	9.56	9.89	9.93	10.05	10.02	9.79	9.37	9.23	9.27	9.35	9.28	9.25	9.26
1988	10.26	10.52	9.91	9.92	10.29	10.53	10.52	10.76	10.85	10.34	9.78	9.80	9.90
1987	9.77	8.62	8.69	8.64	9.15	9.63	9.61	9.70	10.05	10.66	11.11	10.62	10.78
1986	9.30	10.44	9.98	9.16	8.87	9.38	9.36	9.05	9.03	9.28	9.24	9.01	8.81
1985	12.06	12.68	12.87	13.50	13.17	12.65	11.68	11.55	11.65	11.68	11.61	11.10	10.57
1984	13.66	13.02	13.04	13.66	13.93	14.66	14.90	14.42	13.67	13.43	13.38	13.00	12.76
1983	12.83	12.74	13.02	12.67	12.43	12.44	12.64	12.86	13.18	13.04	12.88	12.97	13.14
1982	14.79	16.48	16.33	15.57	15.12	15.01	15.78	15.67	14.71	13.92	13.21	12.92	12.76
1981	15.30	14.03	14.65	14.61	15.23	15.61	14.89	15.42	16.14	16.58	16.28	14.88	15.23
1980	13.00	11.95	13.19	14.09	13.49	11.99	11.73	11.96	12.73	13.18	13.33	13.96	14.37
1979	10.22	9.70	9.74	9.89	9.92	10.19	9.95	9.72	9.75	9.94	10.85	11.57	11.47
1978	9.10	8.76	8.79	8.79	8.86	9.02	9.19	9.26	9.11	9.09	9.28	9.46	9.56
1977	8.43	8.41	8.46	8.49	8.51	8.49	8.37	8.32	8.36	8.32	8.44	8.48	8.55
1976	8.92	9.39	9.16	9.12	9.00	9.06	9.07	9.02	8.83	8.69	8.60	8.61	8.45
1975	9.44	9.45	9.23	9.17	9.48	9.50	9.34	9.38	9.52	9.64	9.55	9.45	9.51
1974	9.04	8.15	8.20	8.35	8.56	8.72	8.93	9.17	9.53	10.05	9.93	9.54	9.37
1973	7.72	7.42	7.52	7.50	7.51	7.51	7.59	7.70	7.92	7.94	7.94	8.01	8.07
1972	7.60	7.76	7.71	7.69	7.75	7.76	7.71	7.58	7.49	7.48	7.50	7.42	7.38
1971	8.00	8.08	7.85	8.00	7.96	8.05	8.28	8.16	8.12	7.98	7.87	7.84	7.82
1970	8.52	8.40	8.30	8.17	8.16	8.54	8.90	8.81	8.67	8.66	8.62	8.63	8.33
1969	7.34	6.90	6.89	7.08	7.11	6.99	7.25	7.38	7.34	7.50	7.71	7.75	8.23
1968	6.35	6.32	6.24	6.26	6.38	6.46	6.46	6.38	6.13	6.12	6.26	6.47	6.75
1967	5.66	5.23	5.06	5.20	5.18	5.42	5.67	5.76	5.82	5.90	5.99	6.29	6.40
1966	5.25	4.78	4.84	5.02	5.12	5.12	5.19	5.28	5.44	5.69	5.55	5.48	5.46
1965	4.52	4.44	4.43	4.44	4.44	4.46	4.49	4.50	4.53	4.57	4.60	4.64	4.75
1964	4.44	4.42	4.40	4.42	4.45	4.45	4.46	4.45	4.45	4.44	4.44	4.45	4.46
1963	4.32	4.28	4.28	4.27	4.29	4.29	4.29	4.32	4.33	4.35	4.37	4.37	4.39
1962	4.41	4.50	4.52	4.50	4.47	4.41	4.38	4.40	4.40	4.37	4.35	4.33	4.31
1961	4.46	4.48	4.39	4.29	4.34	4.38	4.42	4.50	4.57	4.58	4.53	4.49	4.50
1960	4.53	4.76	4.68	4.58	4.54	4.57	4.58	4.54	4.36	[illegible]	4.42	4.45	4.49
1959	4.56	4.27	4.31	4.30	4.40	4.57	4.67	4.64	4.60	[illegible]	4.79	4.68	4.71
1958	3.92	3.73	3.68	3.73	3.72	3.69	3.70	3.79	3.98	4.24	4.29	4.25	4.22
1957	4.03	3.87	3.81	3.80	3.80	3.85	3.94	4.10	4.25	4.31	4.32	4.30	4.05
1956	3.43	3.17	3.13	3.16	3.30	3.34	3.34	3.37	3.48	3.61	3.69	3.76	3.84
1955	3.13	3.01	3.06	3.09	3.08	3.11	3.12	3.13	3.17	3.21	3.18	3.17	3.23
1954	3.00	3.14	3.03	2.93	2.94	2.97	3.00	2.99	2.98	3.00	2.99	2.99	2.99
1953	3.32	3.11	3.18	3.22	3.35	3.50	3.57	3.41	3.38	3.42	3.27	3.20	3.21
1952	3.05	3.06	3.01	3.05	3.02	3.02	3.04	3.05	3.06	3.06	3.08	3.05	3.05
1951	2.95	2.71	2.73	2.87	2.98	2.97	3.06	3.04	2.96	2.92	2.98	3.09	3.11
1950	2.68	2.64	2.64	2.64	2.65	2.69	2.69	2.71	2.66	2.71	2.72	2.72	2.72
1949	2.76	2.82	2.83	2.82	2.83	2.82	2.80	2.75	2.71	2.69	2.69	2.66	2.65
1948	2.92	2.94	2.92	2.90	2.87	2.86	2.85	2.91	2.96	2.95	2.95	2.96	2.91
1947	2.67	2.60	2.60	2.61	2.59	2.60	2.60	2.60	2.60	2.66	2.79	2.85	2.95
1946	2.58	2.57	2.51	2.49	2.51	2.56	2.56	2.55	2.57	2.62	2.65	2.66	2.66
1945	2.67	2.72	2.69	2.67	2.69	2.69	2.65	2.63	2.65	2.66	2.67	2.64	2.65
1944	2.72	2.74	2.74	2.72	2.71	2.70	2.70	2.70	2.69	2.69	2.72	2.75	2.72
1943	2.73	2.79	2.76	2.75	2.75	2.71	2.71	2.68	2.69	2.70	2.70	2.73	2.77
1942	2.87	2.87	2.91	2.92	2.89	2.89	2.89	2.86	2.86	2.85	2.83	2.81	2.83
1941	2.83	2.88	2.88	2.87	2.90	2.87	2.84	2.80	2.81	2.81	2.76	2.74	2.85
1940	2.92	2.94	2.94	2.92	2.88	2.99	2.99	2.92	2.92	2.88	2.89	2.86	2.85
1939	3.03	3.05	3.01	2.99	3.01	2.96	2.97	2.93	2.97	3.31	3.20	2.99	2.97
1938	3.28	3.35	3.35	3.34	3.42	3.31	3.28	3.26	3.26	3.31	3.23	3.14	3.10
1937	3.45	3.33	3.43	3.53	3.56	3.48	3.47	3.44	3.41	3.43	3.48	3.42	3.37
1936	3.57	3.70	3.68	3.67	3.69	3.65	3.60	3.57	3.55	3.54	3.48	3.35	3.31
1935	4.02	4.40	4.26	4.19	4.11	4.05	4.00	3.93	3.93	3.90	3.85	3.81	3.76
1934	4.66	5.29	4.88	4.73	4.66	4.60	4.52	4.46	4.55	4.65	4.59	4.49	4.48
1933	5.02	4.61	4.76	5.06	5.25	5.15	4.93	4.75	4.73	4.97	5.04	5.47	5.47
1932	5.32	5.54	5.69	5.36	5.52	5.63	5.72	5.70	5.27	4.99	4.86	4.84	4.75
1931	4.68	4.64	4.64	4.57	4.54	4.47	4.48	4.48	4.46	4.58	4.99	4.97	5.36
1930	4.75	4.89	4.93	4.83	4.79	4.77	4.76	4.73	4.67	4.62	4.63	4.68	4.74
1929	4.91	4.75	4.81	4.89	4.88	4.90	4.90	4.91	4.97	5.02	5.05	4.96	4.87
1928	4.68	4.61	4.59	4.57	4.57	4.60	4.70	4.71	4.78	4.77	4.75	4.72	4.75
1927	4.76	4.83	4.86	4.83	4.81	4.80	4.79	4.77	4.72	4.73	4.69	4.69	4.65
1926	4.88	4.91	4.91	4.91	4.88	4.86	4.85	4.89	4.88	4.90	4.89	4.86	4.83
1925	5.03	5.15	5.14	5.13	5.06	4.98	4.97	5.00	5.01	4.98	4.97	4.97	4.96
1924	5.30	5.43	5.40	5.42	5.42	5.35	5.28	5.24	5.23	5.25	5.21	5.20	5.17
1923	5.51	5.36	5.40	5.57	5.58	5.52	5.52	5.60	5.48	5.52	5.53	5.49	5.49
1922	5.48	5.76	5.70	5.65	5.53	5.45	5.51	5.46	5.30	5.22	5.34	5.46	5.41
1921	6.55	6.79	6.67	6.73	6.73	6.74	6.79	6.77	6.67	6.46	6.38	6.05	5.76
1920	6.65	6.22	6.32	6.45	6.54	6.90	6.88	6.68	6.92	6.77	6.59	6.69	6.86
1919	5.83	5.64	5.68	5.71	5.76	5.73	5.73	5.79	5.88	5.96	5.91	6.02	6.19

MOODY'S AVERAGE OF YIELDS ON A PUBLIC UTILITY BONDS (IN PERCENT)

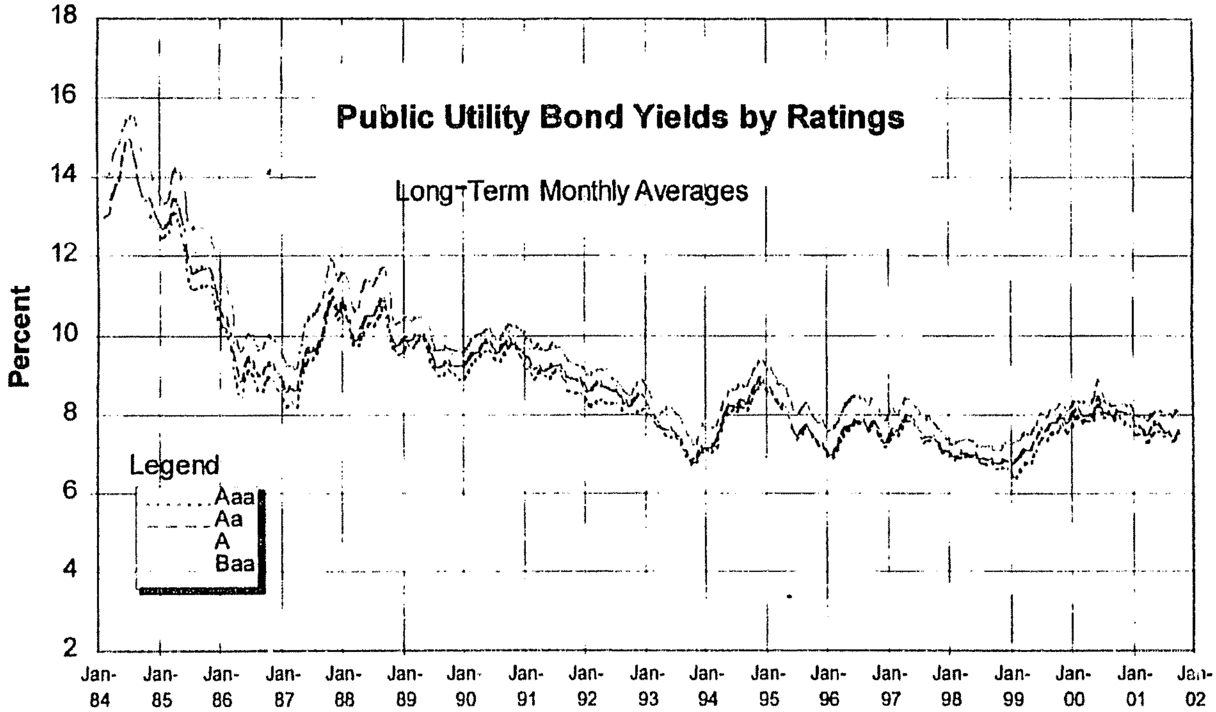
Year	Aver	Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov	Dec.
2001	...	7.80	7.74	7.68	7.94	7.99	7.85	...	...	...	...	...	...
2000	8.24	8.35	8.25	8.28	8.29	8.70	8.36	8.25	8.13	8.23	8.14	8.11	7.84
1999	7.62	6.97	7.09	7.26	7.22	7.47	7.74	7.71	7.91	7.93	8.06	7.94	8.14
1998	7.04	7.04	7.12	7.16	7.16	7.16	7.03	7.03	7.00	6.93	6.96	7.03	6.91
1997	7.60	7.77	7.64	7.87	8.03	7.89	7.72	7.48	7.51	7.47	7.35	7.25	7.16
1996	7.75	7.22	7.37	7.73	7.89	7.98	8.06	8.02	7.84	8.01	7.77	7.49	7.59
1995	7.89	8.73	8.52	8.37	8.27	7.91	7.60	7.70	7.83	7.62	7.46	7.43	7.23
1994	8.31	7.33	7.47	7.85	8.22	8.33	8.31	8.47	8.41	8.64	8.86	8.98	8.76
1993	7.59	8.27	8.04	7.90	7.81	7.86	7.75	7.54	7.25	7.04	7.03	7.30	7.34
1992	8.69	8.84	8.93	8.97	8.93	8.87	8.78	8.57	8.44	8.40	8.54	8.63	8.43
1991	9.36	9.71	9.47	9.55	9.46	9.44	9.59	9.55	9.29	9.16	9.12	9.05	8.88
1990	9.86	9.56	9.76	9.85	9.92	10.00	9.80	9.75	9.92	10.12	10.05	9.90	9.73
1989	9.77	10.08	10.07	10.23	10.18	9.99	9.64	9.50	9.52	9.58	9.54	9.51	9.44
1988	10.49	10.76	10.10	10.09	10.54	10.81	10.79	11.04	11.17	10.61	9.97	9.90	10.06
1987	10.10	8.95	9.00	8.93	9.38	9.91	10.02	10.15	10.45	11.22	11.34	10.82	10.98
1986	9.58	10.79	10.26	9.48	9.14	9.59	9.62	9.37	9.29	9.52	9.52	9.28	9.12
1985	12.47	12.99	13.08	13.87	13.61	13.12	12.13	12.07	12.13	12.13	12.01	11.49	10.97
1984	14.03	13.39	13.41	13.87	14.16	14.90	15.09	14.82	14.43	14.17	13.80	13.23	13.11
1983	13.66	14.24	14.26	13.94	13.61	13.50	13.64	13.58	13.57	13.42	13.25	13.38	13.52
1982	15.86	16.83	16.84	16.50	16.31	16.04	16.42	16.42	15.83	15.40	14.79	14.46	14.43
1981	15.95	14.26	14.91	15.14	15.48	16.25	15.74	16.21	16.58	17.16	17.21	16.20	16.29
1980	13.34	12.27	13.55	14.65	13.87	12.53	12.21	12.26	12.96	13.43	13.58	14.12	14.63
1979	10.49	9.90	9.84	10.04	10.10	10.30	10.14	9.98	10.14	10.36	11.40	11.89	11.79
1978	9.29	8.92	8.97	8.98	9.09	9.22	9.40	9.51	9.32	9.28	9.46	9.68	9.70
1977	8.61	8.61	8.65	8.70	8.71	8.71	8.58	8.51	8.49	8.46	8.61	8.64	8.64
1976	9.29	9.90	9.71	9.67	9.53	9.55	9.54	9.37	9.13	8.90	8.79	8.76	8.62
1975	10.09	10.37	9.99	9.72	10.06	10.23	10.10	10.01	10.12	10.19	10.16	10.04	10.11
1974	9.50	8.36	8.42	8.46	8.77	9.00	9.32	9.66	10.03	10.45	10.78	10.46	10.27
1973	7.84	7.52	7.62	7.66	7.63	7.63	7.71	7.82	8.04	8.04	8.02	8.15	8.24
1972	7.72	7.79	7.78	7.77	7.82	7.84	7.77	7.82	7.64	7.61	7.66	7.60	7.48
1971	8.16	8.15	7.89	8.05	8.07	8.34	8.45	8.45	8.40	8.18	8.10	7.96	7.90
1970	8.69	8.69	8.51	8.31	8.31	8.67	9.04	9.06	8.88	8.82	8.76	8.79	8.48
1969	7.54	7.04	7.13	7.27	7.30	7.16	7.41	7.52	7.44	7.63	8.02	8.00	8.59
1968	6.51	6.54	6.37	6.41	6.58	6.62	6.62	6.53	6.27	6.27	6.40	6.59	6.87
1967	5.87	5.46	5.28	5.44	5.42	5.66	5.84	5.94	5.96	6.05	6.18	6.48	6.67
1966	5.39	4.86	4.92	5.14	5.25	5.25	5.40	5.45	5.58	5.81	5.74	5.63	5.67
1965	4.58	4.53	4.51	4.50	4.49	4.50	4.52	4.54	4.58	4.63	4.66	4.71	4.83
1964	4.52	4.49	4.50	4.51	4.52	4.53	4.55	4.54	4.54	4.53	4.51	4.53	4.54
1963	4.39	4.39	4.37	4.37	4.37	4.37	4.37	4.39	4.38	4.10	4.41	4.42	4.46
1962	4.54	4.65	4.66	4.64	4.59	4.51	4.48	4.50	4.53	4.51	4.49	4.45	4.44
1961	4.62	4.64	4.59	4.48	4.48	4.52	4.57	4.65	4.73	4.73	4.71	4.68	4.65
1960	4.78	5.02	5.00	4.91	4.79	4.86	4.84	4.79	4.64	4.57	4.61	4.62	4.65
1959	4.78	4.52	4.50	4.47	4.56	4.77	4.86	4.88	4.89	5.03	4.96	4.90	4.96
1958	4.20	3.93	3.96	4.13	3.95	4.01	3.99	4.04	4.29	4.55	4.56	4.47	4.49
1957	4.24	3.96	4.05	4.05	4.01	4.01	4.09	4.20	4.37	4.55	4.61	4.62	4.36
1956	3.56	3.31	3.29	3.29	3.40	3.48	3.49	3.55	3.63	3.72	3.79	3.82	3.91
1955	3.22	3.13	3.14	3.15	3.15	3.19	3.21	3.21	3.24	3.27	3.30	3.32	3.35
1954	3.16	3.32	3.23	3.16	3.16	3.14	3.16	3.14	3.13	3.12	3.12	3.11	3.11
1953	3.49	3.25	3.30	3.36	3.47	3.63	3.71	3.66	3.61	3.62	3.49	3.40	3.38
1952	3.24	3.29	3.23	3.25	3.23	3.22	3.22	3.22	3.24	3.24	3.26	3.24	3.22
1951	3.11	2.83	2.84	2.95	3.09	3.13	3.21	3.26	3.19	3.14	3.17	3.24	3.29
1950	2.79	2.76	2.76	2.76	2.77	2.79	2.79	2.79	2.76	2.80	2.83	2.86	2.86
1949	2.90	2.99	2.99	2.97	2.96	2.95	2.94	2.90	2.86	2.85	2.83	2.81	2.78
1948	3.02	3.05	3.05	3.02	2.97	2.94	2.94	2.99	3.03	3.05	3.03	3.07	3.06
1947	2.78	2.72	2.72	2.72	2.70	2.70	2.71	2.73	2.73	2.80	2.88	2.93	3.05
1946	2.71	2.69	2.67	2.66	2.65	2.69	2.70	2.69	2.71	2.75	2.76	2.76	2.76
1945	2.87	2.99	2.98	2.97	2.95	2.92	2.87	2.83	2.80	2.79	2.79	2.77	2.75
1944	2.97	2.99	2.99	2.97	2.99	2.99	2.99	2.96	2.94	2.93	2.94	2.96	2.97
1943	2.99	3.05	3.02	3.01	3.00	3.00	2.98	2.96	2.96	2.96	2.97	2.98	2.99
1942	3.09	3.09	3.09	3.12	3.09	3.10	3.12	3.10	3.10	3.08	3.08	3.07	3.06
1941	3.07	3.15	3.20	3.16	3.14	3.08	3.03	3.00	2.98	3.00	3.00	2.98	3.06
1940	3.24	3.34	3.35	3.34	3.25	3.30	3.34	3.23	3.21	3.18	3.15	3.11	3.10
1939	3.52	3.68	3.59	3.54	3.55	3.50	3.47	3.43	3.41	3.71	3.58	3.41	3.38
1938	3.90	4.01	4.03	3.99	4.08	3.95	3.95	3.86	3.84	3.88	3.79	3.73	3.74
1937	3.98	3.82	3.89	4.09	4.07	4.00	3.99	3.94	3.89	3.96	4.09	4.08	4.03
1936	4.08	4.21	4.17	4.17	4.17	4.14	4.12	4.07	4.06	4.05	4.04	3.95	3.83
1935	4.61	5.18	4.96	4.88	4.79	4.61	4.53	4.42	4.44	4.43	4.40	4.35	4.29
1934	5.55	6.56	5.78	5.66	5.44	5.39	5.40	5.29	5.43	5.56	5.40	5.38	5.36
1933	6.32	5.39	5.77	6.34	6.89	6.50	6.11	5.91	5.98	6.36	6.36	7.06	7.22
1932	6.46	6.17	6.41	6.06	6.83	7.36	7.57	7.28	6.35	5.91	5.81	5.88	5.85
1931	5.12	5.01	5.01	4.98	4.86	4.84	4.87	4.83	4.81	5.05	5.54	5.51	6.24
1930	5.06	5.26	5.29	5.18	5.15	5.04	5.01	4.99	4.95	4.86	4.88	4.96	5.11
1929	5.22	5.05	5.10	5.14	5.14	5.14	5.23	5.24	5.30	5.38	5.34	5.29	5.23
1928	4.95	4.85	4.85	4.82	4.82	4.87	4.99	5.04	5.08	5.05	4.99	4.98	5.05
1927	5.02	5.10	5.13	5.13	5.04	5.04	5.05	5.05	5.02	4.98	4.95	4.92	4.88
1926	5.17	5.29	5.21	5.23	5.20	5.15	5.11	5.13	5.15	5.17	5.18	5.15	5.12
1925	5.42	5.61	5.52	5.53	5.52	5.25	5.25	5.37	5.42	5.40	5.39	5.43	5.36
1924	5.80	6.02	6.00	5.97	5.94	5.91	5.79	5.68	5.70	5.71	5.65	5.62	5.63
1923	5.97	5.85	5.83	6.06	6.04	6.00	6.06	6.02	5.77	5.95	5.98	6.00	6.05
1922	6.00	6.41	6.32	6.22	6.06	5.93	5.91	5.89	5.86	5.69	5.83	5.87	5.95
1921	7.38	7.74	7.65	7.61	7.61	7.66	7.64	7.72	7.67	7.32	7.04	6.55	6.32
1920	7.57	6.87	7.03	7.04	7.36	7.72	7.73	7.82	7.96	7.83	7.75	7.73	7.96
1919	6.35	6.35	6.39	6.41	6.18	6.27	6.19	6.16	6.26	6.44	6.41	6.67	6.79

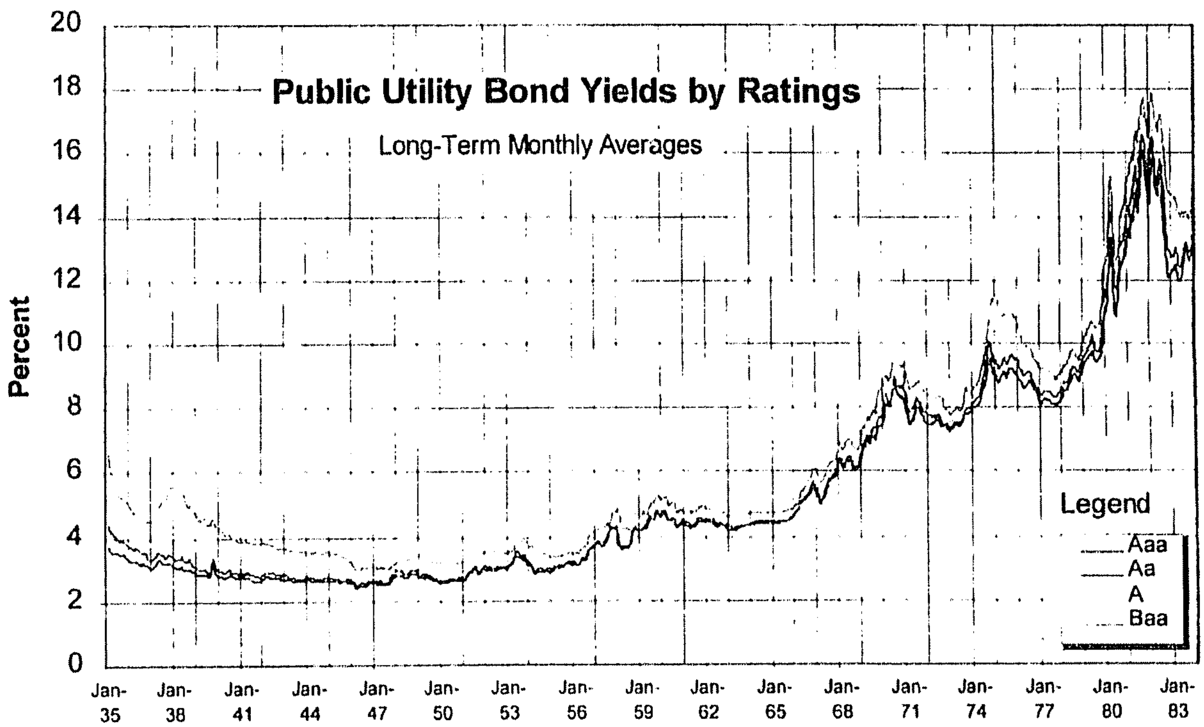
MOODY'S AVERAGE OF YIELDS ON Baa PUBLIC UTILITY BONDS (IN PERCENT)

Year	Aver	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug.	Sep	Oct	Nov	Dec
2001		7.99	7.94	7.85	8.06	8.11	8.02						
2000	8.36	8.40	8.33	8.40	8.40	8.86	8.47	8.33	8.25	8.32	8.29	8.25	8.01
1999	7.88	7.30	7.41	7.55	7.51	7.71	8.03	7.97	8.16	8.19	8.32	8.12	8.28
1998	7.26	7.28	7.36	7.37	7.37	7.34	7.21	7.23	7.20	7.13	7.13	7.31	7.24
1997	7.95	8.18	8.02	8.26	8.42	8.28	8.12	7.87	7.92	7.79	7.67	7.49	7.41
1996	8.17	7.64	7.78	8.15	8.32	8.45	8.51	8.44	8.25	8.41	8.15	7.87	7.98
1995	8.29	9.15	8.93	8.78	8.67	8.30	8.01	8.11	8.24	7.98	7.82	7.81	7.63
1994	8.63	7.66	7.76	8.11	8.47	8.61	8.64	8.80	8.74	8.98	9.24	9.35	9.16
1993	7.91	8.57	8.31	8.10	8.11	8.18	8.05	7.93	7.59	7.35	7.27	7.69	7.73
1992	8.86	8.98	9.00	9.16	9.11	9.01	8.90	8.69	8.58	8.54	8.76	8.86	8.69
1991	9.55	9.96	9.68	9.74	9.64	9.64	9.79	9.69	9.47	9.34	9.32	9.28	9.07
1990	10.06	9.74	9.96	10.06	10.13	10.16	9.96	9.92	10.12	10.32	10.28	10.12	9.96
1989	9.97	10.38	10.38	10.50	10.49	10.29	9.80	9.64	9.64	9.70	9.64	9.64	9.60
1988	11.00	11.34	10.65	10.69	11.23	11.38	11.27	11.52	11.69	11.13	10.32	10.35	10.44
1987	10.53	9.27	9.24	9.19	9.85	10.40	10.46	10.62	10.90	11.58	11.91	11.40	11.55
1986	10.00	11.24	10.74	9.91	9.63	10.02	10.03	9.69	9.70	9.96	9.95	9.69	9.49
1985	12.96	13.36	13.44	14.19	14.11	13.62	12.66	12.70	12.73	12.72	12.52	12.04	11.48
1984	14.53	14.05	14.05	14.56	14.82	15.28	15.50	15.50	14.79	14.51	14.17	13.72	13.46
1983	14.20	14.56	14.61	14.33	14.67	14.05	14.16	14.01	14.21	14.10	13.95	14.12	14.23
1982	16.45	17.83	17.83	17.16	17.00	16.68	17.21	17.09	16.37	15.68	15.10	14.81	14.69
1981	16.60	15.30	15.86	15.83	16.14	16.66	16.30	16.98	17.19	17.76	17.71	16.49	17.02
1980	13.95	12.92	14.42	15.26	14.35	12.93	12.63	12.75	13.50	14.07	14.43	14.79	15.29
1979	10.96	10.29	10.27	10.53	10.56	10.70	10.56	10.48	10.50	10.78	11.89	12.48	12.51
1978	9.62	9.27	9.29	9.37	9.54	9.70	9.78	9.73	9.53	9.47	9.69	9.99	10.08
1977	9.06	9.17	9.19	9.20	9.17	9.13	9.02	8.97	8.91	8.85	9.01	9.06	9.08
1976	9.82	10.55	10.31	10.17	9.95	9.91	10.01	9.88	9.67	9.47	9.41	9.34	9.21
1975	10.96	11.57	11.32	10.94	10.86	10.95	10.85	10.80	10.87	10.89	10.89	10.78	10.79
1974	9.84	8.58	8.68	8.81	9.04	9.23	9.48	9.72	10.14	10.59	11.03	11.38	11.40
1973	8.17	7.77	7.88	7.95	7.96	7.91	7.94	8.10	8.47	8.61	8.44	8.44	8.51
1972	8.17	8.37	8.32	8.26	8.30	8.30	8.31	8.36	8.22	8.01	7.94	7.86	7.78
1971	8.63	8.76	8.55	8.63	8.58	8.68	8.79	8.78	8.80	8.59	8.48	8.47	8.44
1970	9.18	9.00	8.96	8.81	8.94	9.20	9.52	9.48	9.34	9.32	9.27	9.29	9.01
1969	7.93	7.42	7.39	7.61	7.68	7.56	7.77	7.92	7.82	8.11	8.47	8.53	8.89
1968	6.87	6.76	6.68	6.75	6.94	6.99	7.01	6.92	6.72	6.67	6.74	7.01	7.23
1967	6.15	5.83	5.63	5.69	5.74	5.93	6.14	6.23	6.29	6.32	6.42	6.63	6.91
1966	5.60	4.99	5.02	5.19	5.39	5.44	5.52	5.61	5.79	6.06	6.07	6.06	6.09

Year	Aver.	Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
1965	4.78	4.71	4.69	4.68	4.69	4.71	4.77	4.78	4.79	4.82	4.85	4.89	4.97
1964	4.74	4.74	4.74	4.73	4.75	4.73	4.74	4.75	4.75	4.73	4.72	4.72	4.72
1963	4.67	4.65	4.65	4.66	4.67	4.67	4.67	4.67	4.66	4.69	4.66	4.68	4.73
1962	4.75	4.86	4.86	4.85	4.81	4.74	4.68	4.68	4.72	4.74	4.71	4.65	4.66
1961	4.83	4.79	4.76	4.72	4.74	4.77	4.78	4.84	4.90	4.91	4.92	4.89	4.88
1960	4.97	5.20	5.23	5.11	4.96	5.08	5.05	5.03	4.81	4.71	4.82	4.80	4.78
1959	4.96	4.71	4.77	4.69	4.68	4.87	4.97	5.03	5.04	5.17	5.29	5.20	5.13
1958	4.43	4.60	4.23	4.25	4.25	4.23	4.20	4.19	4.44	4.69	4.74	4.67	4.65
1957	4.46	4.26	4.26	4.25	4.24	4.28	4.33	4.41	4.19	4.66	4.73	4.82	4.81
1956	3.78	3.50	3.50	3.51	3.59	3.62	3.65	3.70	3.84	4.02	4.15	4.15	4.18
1955	3.43	3.37	3.38	3.38	3.40	3.40	3.41	3.43	3.46	3.48	3.47	3.48	3.50
1954	3.51	3.72	3.69	3.58	3.53	3.51	3.50	3.48	3.47	3.44	3.41	3.39	3.38
1953	3.73	3.51	3.53	3.56	3.62	3.76	3.80	3.83	3.88	3.93	3.86	3.78	3.72
1952	3.53	3.57	3.55	3.55	3.54	3.54	3.55	3.53	3.50	3.50	3.50	3.47	3.50
1951	3.39	3.21	3.21	3.23	3.31	3.38	3.45	3.49	3.48	3.44	3.49	3.49	3.53
1950	3.18	3.18	3.17	3.16	3.15	3.15	3.15	3.18	3.18	3.19	3.20	3.21	3.21
1949	3.28	3.42	3.40	3.36	3.31	3.30	3.28	3.25	3.25	3.22	3.19	3.17	3.16
1948	3.36	3.30	3.31	3.29	3.28	3.27	3.29	3.34	3.40	3.42	3.44	3.48	3.37
1947	3.08	3.05	3.03	3.04	3.04	3.03	3.04	3.03	3.02	3.06	3.13	3.18	3.25
1946	3.03	3.07	3.00	2.96	2.98	3.02	3.04	3.03	3.02	3.06	3.06	3.07	3.07
1945	3.39	3.50	3.48	3.48	3.49	3.47	3.43	3.40	3.37	3.34	3.29	3.22	3.15
1944	3.52	3.54	3.53	3.52	3.53	3.53	3.53	3.51	3.51	3.51	3.53	3.54	3.50
1943	3.58	3.65	3.61	3.58	3.60	3.60	3.60	3.55	3.55	3.55	3.53	3.55	3.55
1942	3.73	3.83	3.81	3.84	3.79	3.76	3.73	3.68	3.67	3.66	3.66	3.67	3.68
1941	3.84	3.87	3.90	3.90	3.86	3.85	3.83	3.82	3.80	3.80	3.82	3.82	3.85
1940	4.05	4.30	4.23	4.14	4.06	4.10	4.15	3.99	3.98	3.94	3.92	3.88	3.86
1939	4.50	4.66	4.59	4.53	4.62	4.50	4.41	4.39	4.39	4.64	4.48	4.38	4.36
1938	5.26	5.59	5.79	5.80	5.82	5.32	5.33	5.01	4.93	5.05	4.90	4.77	4.77
1937	5.09	4.50	4.55	4.75	4.98	5.02	5.17	5.08	5.04	5.25	5.53	5.59	5.60
1936	4.67	4.88	4.80	4.78	4.77	4.76	4.72	4.62	4.59	4.54	4.53	4.53	4.53
1935	5.56	6.60	6.20	5.99	5.94	5.51	5.41	5.22	5.22	5.25	5.24	5.12	5.07
1934	7.49	8.86	7.58	7.58	7.18	7.17	7.20	7.36	7.68	7.62	7.38	7.21	7.03
1933	9.38	8.14	8.89	9.87	10.64	9.30	8.63	8.26	8.75	9.71	9.90	10.30	10.12
1932	8.78	8.18	8.33	8.31	9.56	10.21	10.70	10.11	7.92	7.48	7.87	8.32	8.41
1931	6.90	6.36	6.37	6.18	6.19	6.36	6.60	6.47	6.60	7.04	8.01	7.80	8.81
1930	5.88	5.92	5.93	5.80	5.77	5.76	5.78	5.78	5.70	5.63	5.82	6.15	6.56
1929	5.76	5.48	5.52	5.62	5.69	5.66	5.72	5.79	5.89	5.92	5.91	6.00	5.96
1928	5.33	5.24	5.20	5.18	5.18	5.23	5.38	5.38	5.43	5.45	5.43	5.38	5.42
1927	5.46	5.51	5.54	5.54	5.49	5.50	5.51	5.48	5.43	5.41	5.39	5.38	5.32
1926	5.67	5.81	5.76	5.80	5.75	5.67	5.61	5.61	5.62	5.62	5.61	5.58	5.54
1925	5.91	6.12	6.08	6.02	5.99	5.85	5.82	5.83	5.87	5.85	5.83	5.81	5.88
1924	6.38	6.73	6.64	6.60	6.55	6.42	6.32	6.23	6.24	6.24	6.21	6.24	6.13
1923	6.75	6.59	6.60	6.73	6.78	6.78	6.80	6.79	6.77	6.81	6.79	6.78	6.80
1922	7.03	7.83	7.74	7.55	7.29	6.86	6.92	6.83	6.88	6.77	6.51	6.56	6.56
1921	8.40	8.51	8.50	8.51	8.52	8.54	8.62	8.64	8.66	8.30	8.40	7.92	7.68
1920	7.99	7.30	7.48	7.59	7.88	8.03	7.99	8.21	8.21	8.29	8.27	8.28	8.36
1919	6.93	6.89	6.91	6.91	6.88	6.84	6.84	6.79	6.80	6.94	7.01	7.08	7.25

Note. The tables above give the monthly average yields of long-term utility bonds (**Aaa, Aa, A** and **Baa**). All yields are calculated to maturity dates and the list of bonds used is adjusted when required to reflect rating changes or other reasons so that each of the series is comparable throughout the entire period. Average yields for the periods presented are not intended to be indicative of yields which may prevail in the future.


Public Utility Bond Yields by Ratings
Long-Term Monthly Averages
Percent
18
16
14
12
10
8
6
4
2
Legend
Aaa
Aa
A
Baa
Jan-84
Jan-85
Jan-86
Jan-87
Jan-88
Jan-89
Jan-90
Jan-91
Jan-92
Jan-93
Jan-94
Jan-95
Jan-96
Jan-97
Jan-98
Jan-99
Jan-00
Jan-01
Jan-02


Public Utility Bond Yields by Ratings
Long-Term Monthly Averages
Percent
20
18
16
14
12
10
8
6
4
2
0
Legend
Aaa
Aa
A
Baa
Jan-35
Jan-38
Jan-41
Jan-44
Jan-47
Jan-50
Jan-53
Jan-56
Jan-59
Jan-62
Jan-65
Jan-68
Jan-71
Jan-74
Jan-77
Jan-80
Jan-83

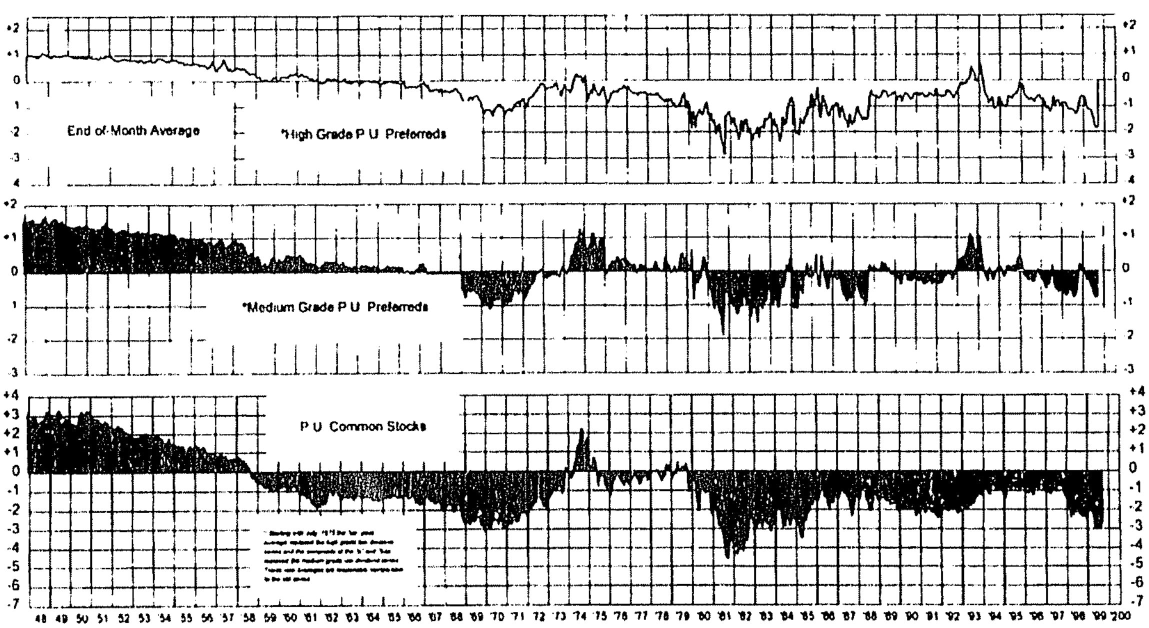
MOODY'S PREFERRED STOCK YIELD AVERAGES (IN PER CENT)

LOW DIVIDEND SERIES

HIGH GRADE PUBLIC UTILITIES

Year	Aver.	Jan.	Feb	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
1975	9.45	9.19	9.14	9.31	9.48	9.74	9.34	9.36	9.59	9.78	9.58	9.43	9.41
1974	9.26	7.95	7.99	8.06	8.37	8.84	9.32	9.73	10.00	10.41	10.38	9.91	10.17
1973	7.56	7.23	7.32	7.39	7.37	7.42	7.53	7.74	7.81	7.72	7.50	7.69	8.04
1972	7.23	6.86	6.92	7.08	7.26	7.23	7.28	7.35	7.25	7.37	7.48	7.36	7.32
1971	7.10	6.68	6.77	6.91	7.01	7.15	7.31	7.37	7.34	7.28	7.07	7.17	7.15
1970	7.56	7.21	7.30	7.26	7.32	7.67	7.84	7.72	7.77	7.76	7.85	7.66	7.30
1969	6.76	6.18	6.23	6.39	6.42	6.59	6.71	6.75	6.85	7.09	7.05	7.27	7.54
1968	6.07	5.93	5.95	6.04	6.13	6.19	6.17	6.01	5.95	5.97	6.01	6.15	6.32
1967	5.54	5.16	5.15	5.15	5.23	5.34	5.49	5.52	5.62	5.70	5.86	6.05	6.25
1966	5.19	4.73	4.89	4.96	4.97	5.00	5.12	5.21	5.46	5.56	5.42	5.46	5.46
1965	4.53	4.37	4.43	4.43	4.43	4.52	4.56	4.52	4.55	4.57	4.61	4.66	4.72
1964	4.49	4.42	4.41	4.50	4.53	4.57	4.54	4.51	4.48	4.47	4.49	4.48	4.44
1963	4.38	4.36	4.36	4.37	4.40	4.32	4.33	4.35	4.32	4.42	4.41	4.44	4.47
1962	4.52	4.58	4.52	4.48	4.49	4.44	4.57	4.58	4.54	4.55	4.54	4.46	4.44
1961	4.71	4.74	4.71	4.69	4.69	4.69	4.75	4.74	4.77	4.77	4.72	4.61	4.68
1960	4.85	4.95	4.89	4.88	4.90	4.94	4.90	4.80	4.70	4.78	4.81	4.83	4.87
1959	4.79	4.64	4.59	4.56	4.62	4.75	4.85	4.79	4.78	4.93	4.96	4.98	5.04
1958	4.51	4.37	4.39	4.44	4.34	4.36	4.38	4.42	4.63	4.73	4.72	4.68	4.68
1957	4.72	4.44	4.37	4.48	4.52	4.64	4.93	4.96	4.91	4.90	4.99	4.88	4.59
1956	4.18	3.94	3.92	3.98	4.05	4.07	4.07	4.11	4.19	4.29	4.37	4.54	4.68
1955	3.94	3.94	3.95	3.96	3.90	3.93	3.95	3.92	3.94	3.97	3.94	3.96	3.96
1954	3.94	4.03	3.94	3.89	4.01	4.02	4.00	3.97	3.92	3.88	3.85	3.85	3.90
1953	4.22	4.05	4.09	4.14	4.28	4.32	4.45	4.31	4.28	4.27	4.16	4.16	4.15
1952	4.04	4.13	4.07	4.05	3.99	3.96	3.98	4.02	4.05	4.07	4.05	3.99	4.00
1951	4.00	3.79	3.78	3.89	3.98	4.02	4.10	4.09	4.02	4.01	4.11	4.24	4.24
1950	3.75	3.80	3.76	3.72	3.73	3.71	3.73	3.75	3.73	3.74	3.78	3.74	3.81
1949	3.84	3.95	3.91	3.91	3.98	3.92	3.91	3.85	3.82	3.84	3.85	3.83	3.83
1948	4.03	4.03	4.04	3.98	3.94	3.91	3.94	3.96	4.09	4.14	4.17	4.15	4.04
1947	3.63	3.56	3.56	3.58	3.59	3.58	3.60	3.58	3.55	3.61	3.68	3.80	4.04
1946													

Spreads of P.U. Stocks from Moody's Composite P.U. Bond Average



MEDIUM GRADE PUBLIC UTILITIES

Year	Aver	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1975	10.64	10.73	10.23	10.48	10.63	11.00	10.88	10.75	10.85	10.71	10.58	10.41	10.39
1974	9.88	8.36	8.27	8.61	8.87	9.41	9.64	10.16	10.72	10.94	11.50	10.93	11.20
1973	7.78	7.42	7.41	7.51	7.51	7.59	7.62	7.81	8.06	8.04	7.94	8.12	8.35
1972	7.43	7.00	7.13	7.26	7.39	7.49	7.43	7.56	7.51	7.61	7.58	7.52	7.56
1971	7.36	6.97	6.96	7.11	7.23	7.44	7.58	7.71	7.66	7.55	7.34	7.37	7.39
1970	7.78	7.50	7.51	7.47	7.57	7.76	8.13	7.96	7.98	8.00	7.95	7.90	7.51
1969	6.91	6.45	6.45	6.58	6.59	6.69	6.87	6.87	6.93	7.08	7.17	7.44	7.80
1968	6.28	6.18	6.19	6.25	6.30	6.42	6.33	6.25	6.19	6.17	6.23	6.31	6.52
1967	5.77	5.44	5.50	5.47	5.52	5.59	5.76	5.71	5.81	5.86	5.98	6.15	6.46
1966	5.41	4.96	5.07	5.21	5.19	5.27	5.35	5.30	5.57	5.72	5.68	5.74	5.72
1965	4.72	4.58	4.56	4.59	4.62	4.69	4.74	4.72	4.72	4.80	4.81	4.88	4.94
1964	4.68	4.64	4.64	4.72	4.70	4.72	4.71	4.69	4.68	4.64	4.69	4.70	4.68
1963	4.58	4.60	4.57	4.58	4.58	4.56	4.57	4.57	4.56	4.56	4.59	4.61	4.66
1962	4.71	4.78	4.73	4.74	4.71	4.68	4.75	4.78	4.77	4.77	4.74	4.70	4.69
1961	4.90	4.98	4.94	[illegible]	4.92	4.89	4.87	4.90	4.90	4.92	4.90	4.85	4.83
1960	5.06	5.25	5.11	5.09	5.04	5.07	5.09	5.06	4.94	5.00	5.01	5.03	5.00
1959	5.01	4.87	4.87	4.88	4.86	4.94	4.96	5.01	4.99	5.13	5.14	5.19	5.33
1958	4.83	4.76	4.83	4.77	4.73	4.72	4.75	4.79	4.90	4.92	4.95	4.93	4.95
1957	5.01	4.76	4.77	4.79	4.81	4.95	5.06	5.15	5.13	5.18	5.26	5.27	5.01
1956	4.49	4.27	4.26	4.30	4.38	4.43	4.41	4.41	4.53	4.63	4.66	4.78	4.82
1955	4.25	4.26	4.26	4.28	4.19	4.23	4.20	4.25	4.32	4.30	4.27	4.25	4.26
1954	4.27	4.32	4.32	4.27	4.29	4.29	4.29	4.25	4.23	4.18	4.19	4.20	4.21
1953	4.62	4.43	4.44	4.52	4.66	4.75	4.87	4.70	4.69	4.73	4.53	4.55	4.53
1952	4.45	4.52	4.51	4.49	4.40	4.33	4.39	4.38	4.43	4.47	4.49	4.42	4.43
1951	4.41	4.22	4.19	4.33	4.40	4.30	4.48	4.46	4.37	4.41	4.54	4.63	4.71

Year	Aver.	Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
1950	4.18	4.16	4.15	4.13	4.15	4.13	4.17	4.19	4.19	4.21	4.20	4.23	4.25
1949	4.39	4.49	4.43	4.42	4.47	4.49	4.49	4.42	4.30	4.32	4.33	4.25	4.19
1948	4.53	4.51	4.52	4.51	4.50	4.50	4.45	4.50	4.51	4.55	4.55	4.62	4.62
1947	3.97	3.82	3.79	3.82	3.81	3.85	3.87	3.87	3.91	3.98	4.19	4.34	4.59
1946	3.77	3.80	3.78	3.76	3.78	3.73	3.70	3.71	3.71	3.80	3.77	3.80	3.85

Note: Yields are based on the closing prices for the last Friday of each month. Averages are not available prior to 1946 because of the lack of suitable issues. Starting with July 1975 the "aa" yield average replaced the high grade low dividend series and the composite average of the "a" and "baa" replaced the medium grade low dividend series. These new averages, see below, are reasonably comparable to the old series.

MOODY'S PUBLIC UTILITY PREFERRED STOCK YIELD AVERAGES

Year	Jan	Feb	Mar.	Apr.	May	Jun	Jul	Aug	Sep.	Oct	Nov.	Dec.
						"aa"						
2001	6.72	6.63	6.64	6.75	6.76	6.72	...	...	...	...	...	...
2000	6.56	6.62	6.67	6.75	6.81	6.95	6.90	6.81	6.89	6.75	6.67	6.53
1999	6.13	6.14	6.08	6.16	6.31	6.23	6.05	6.05	6.07	6.36	6.46	6.60
1998	6.15	6.23	6.10	6.11	5.93	5.83	5.85	5.64	5.49	6.01	6.16	6.23
1997	7.04	6.88	6.98	6.95	6.69	6.67	6.67	6.58	6.65	6.42	6.21	6.23
1996	6.98	7.08	7.18	7.21	7.25	7.21	7.21	7.27	7.17	6.98	6.80	6.92
1995	7.75	7.47	7.42	7.25	7.05	7.08	7.12	7.10	7.05	6.95	6.92	7.00
1994	7.12	7.22	7.24	7.26	7.54	7.60	7.53	7.73	7.73	7.85	7.90	8.17
1993	7.85	7.79	7.70	7.67	7.70	7.62	7.57	7.53	7.47	7.32	7.35	7.37
1992	8.15	8.13	8.18	8.20	8.11	8.18	7.94	7.90	7.78	7.87	7.95	7.88
1991	8.97	8.73	8.87	8.75	8.70	8.77	8.70	8.57	8.39	8.38	8.31	8.23
1990	8.84	9.06	9.18	9.22	9.20	9.17	9.06	9.33	9.30	9.20	9.09	9.08
1989	9.33	9.42	9.54	9.49	9.33	8.93	8.80	8.82	8.91	8.78	8.80	8.88
1988	9.06	8.91	9.06	9.20	9.38	9.28	9.52	9.62	9.40	9.34	9.40	9.50
1987	7.78	7.85	7.82	8.17	8.90	8.66	8.73	8.90	9.40	9.67	9.19	9.35
1986	9.54	8.78	8.61	8.13	8.39	8.54	8.49	8.01	8.09	7.88	7.83	7.98
1985	11.72	11.39	11.62	11.24	10.66	10.25	10.38	10.41	10.60	10.58	10.05	10.00
1984	11.96	12.00	12.40	12.50	12.96	13.23	13.05	12.55	12.31	12.24	12.18	12.25
1983	11.36	11.21	11.17	11.06	11.09	11.34	11.73	11.73	11.70	11.77	11.80	12.18
1982	15.00	14.89	14.44	13.85	13.37	14.30	14.28	12.87	12.84	12.00	11.55	11.63
1981	13.13	13.42	13.35	13.61	13.71	13.75	13.88	14.18	14.68	15.12	13.75	14.97
1980	10.96	11.62	13.09	11.67	10.80	10.59	10.98	11.47	12.02	12.55	13.18	13.15
1979	9.05	9.11	9.10	9.14	9.19	9.03	8.98	9.07	9.60	10.62	10.66	10.86
1978	8.31	8.38	8.35	8.51	8.61	8.84	8.80	8.56	8.43	8.61	8.75	8.94
1977	8.36	8.23	8.21	8.16	8.14	8.03	7.91	8.02	7.95	8.08	8.15	8.14
1976	8.79	8.74	8.92	8.77	8.90	8.92	8.80	8.72	8.58	8.49	8.57	8.28
						"a"						
2001	7.42	7.38	7.35	7.47	7.48	7.36	...	...	...	...	...	...
2000	6.84	6.80	6.82	6.93	6.94	7.05	7.05	6.96	7.05	7.02	7.13	7.38
1999	6.43	6.50	6.44	6.55	6.69	6.65	6.60	5.64	6.67	6.72	6.79	6.81
1998	6.38	6.37	6.40	6.42	6.33	6.21	6.06	5.85	5.75	6.45	6.65	6.50
1997	7.08	6.91	7.01	6.98	6.99	6.95	6.80	6.57	6.69	6.62	6.50	6.52
1996	7.03	7.12	7.23	7.37	7.35	7.26	7.28	7.33	7.21	7.03	6.83	6.96
1995	8.57	8.25	7.91	7.89	7.45	7.45	7.55	7.47	7.35	7.10	7.01	7.08
1994	7.48	7.60	7.65	7.74	7.93	7.90	8.10	8.12	8.25	8.37	8.35	8.65
1993	8.14	8.09	8.06	8.03	8.06	8.08	8.05	7.98	7.87	7.67	7.68	7.62
1992	8.25	8.26	8.32	8.34	8.28	8.26	8.21	8.15	8.12	8.14	8.19	8.16
1991	9.19	8.98	9.07	8.93	8.85	8.89	8.87	8.65	8.59	8.54	8.48	8.34
1990	9.30	9.50	9.47	9.64	9.60	9.46	9.46	9.67	9.70	9.51	9.32	9.30
1989	9.89	10.08	10.11	9.99	9.86	9.37	9.37	9.32	9.43	9.26	9.11	9.25
1988	9.62	9.49	9.74	9.87	10.05	9.89	10.02	10.04	9.89	9.81	9.91	10.06
1987	8.38	8.43	8.36	9.21	9.44	9.13	9.41	9.57	10.19	10.48	10.01	10.24
1986	10.05	9.11	9.05	8.67	9.04	9.32	9.20	8.55	8.76	8.37	8.54	8.64
1985	12.37	11.84	12.32	11.99	11.25	10.83	11.07	11.09	11.05	11.27	10.64	10.28
1984	12.56	12.59	13.12	13.47	14.04	14.22	13.86	13.37	13.13	12.89	12.57	12.97
1983	11.93	11.86	11.79	11.57	11.46	12.05	12.29	12.21	12.15	12.18	12.46	12.61
1982	15.55	15.36	14.81	14.35	13.89	14.69	14.65	13.40	13.49	12.48	12.13	12.20
1981	13.85	14.21	13.72	14.04	14.20	14.15	14.30	15.03	15.28	15.60	14.10	15.47
1980	11.79	12.92	14.74	12.22	11.69	10.97	11.49	12.15	12.92	13.55	13.97	14.01
1979	9.61	9.66	9.63	9.71	9.91	9.55	9.60	9.74	10.34	11.38	11.23	11.49
1978	8.70	8.74	8.79	8.88	9.07	9.39	9.33	8.97	8.82	9.07	9.27	9.65
1977	8.83	8.80	8.75	8.61	8.64	8.47	8.23	8.30	8.32	8.50	8.55	8.59
1976	9.43	9.42	9.52	9.24	9.46	9.46	9.37	9.31	9.04	8.95	8.99	8.80
						"baa"						
2001	7.53	7.48	7.48	7.59	7.57	7.60	...	...	...	...	...	...
2000	8.26	8.30	8.23	8.27	8.25	8.06	8.09	8.00	8.05	7.81	7.69	7.54
1999	7.40	7.48	7.48	7.55	7.54	7.66	7.68	7.61	7.55	7.89	8.01	8.34
1998	6.49	6.52	6.45	6.79	6.81	6.61	6.52	6.52	6.52	7.23	7.39	7.37
1997	8.15	8.04	8.12	8.10	8.08	8.20	8.19	7.91	7.22	6.76	6.69	6.65
1996	8.02	8.08	8.07	8.18	8.18	8.08	8.18	8.25	8.12	8.11	8.06	8.15
1995	8.96	8.73	8.55	8.51	8.18	8.23	8.28	8.19	8.15	8.04	8.00	8.00
1994	8.18	8.27	8.35	8.42	8.56	8.62	8.63	8.60	8.85	9.10	9.43	9.22
1993	8.43	8.43	8.41	8.38	8.33	8.38	8.32	8.27	8.31	8.21	8.33	8.35
1992	8.45	8.49	8.65	8.70	8.88	8.65	8.47	8.44	8.42	8.46	8.56	8.53
1991	9.42	9.10	9.20	9.12	9.08	9.19	9.10	8.91	8.82	8.68	8.64	8.57
1990	9.39	9.54	9.63	9.68	9.73	9.71	9.63	9.73	9.84	9.77	9.49	9.54
1989	10.14	10.27	10.38	10.24	10.13	9.73	9.59	9.58	9.73	9.39	9.30	9.38
1988	9.92	9.88	10.04	10.02	10.25	10.09	10.19	10.33	10.17	10.06	10.15	10.37
1987	8.76	8.88	8.90	9.60	10.07	9.75	9.71	9.93	10.47	10.75	10.19	10.45
1986	10.75	9.93	9.78	9.18	9.68	9.89	9.60	9.26	9.36	9.09	9.01	9.27
1985	12.99	12.87	12.98	12.58	12.26	11.97	11.74	12.38	12.52	12.40	11.27	11.09
1984	12.81	13.03	13.55	13.97	14.49	14.85	14.88	14.21	14.28	14.04	13.50	13.71
1983	12.76	12.66	12.51	12.34	12.07	12.47	12.81	12.73	12.72	12.64	12.95	13.34
1982	15.83	15.65	15.48	15.09	14.93	15.67	15.40	14.21	14.11	13.29	12.94	13.26
1981	14.45	14.82	14.57	15.12	15.34	15.02	15.47	15.85	16.01	16.16	14.74	15.83
1980	12.74	14.08	15.22	13.13	12.29	12.05	12.32	13.05	13.76	14.32	14.86	14.56
1979	10.42	10.37	10.33	10.43	10.82	10.49	10.33	10.49	10.97	11.94	12.18	12.75
1978	9.17	9.17	9.24	9.34	9.54	9.81	9.76	9.54	9.62	9.66	9.89	10.48
1977	9.01	8.98	9.01	9.00	9.04	8.92	8.63	8.72	8.87	8.98	8.96	9.03
1976	9.78	9.57	9.73	9.62	9.76	9.79	9.74	9.67	9.45	9.30	9.30	9.15

Note: The issues in our averages, all of which have "new money" tax status, lack of a sinking fund, and broad marketability. There is no "aaa" average because of an insufficient number of prime-quality preferred stocks. Yields are based on prices for the last Friday of each Month. Series begun July 25, 1975. Weekly averages are published in the "News Reports", which supplements this Manual, and Moody's Bond Survey.

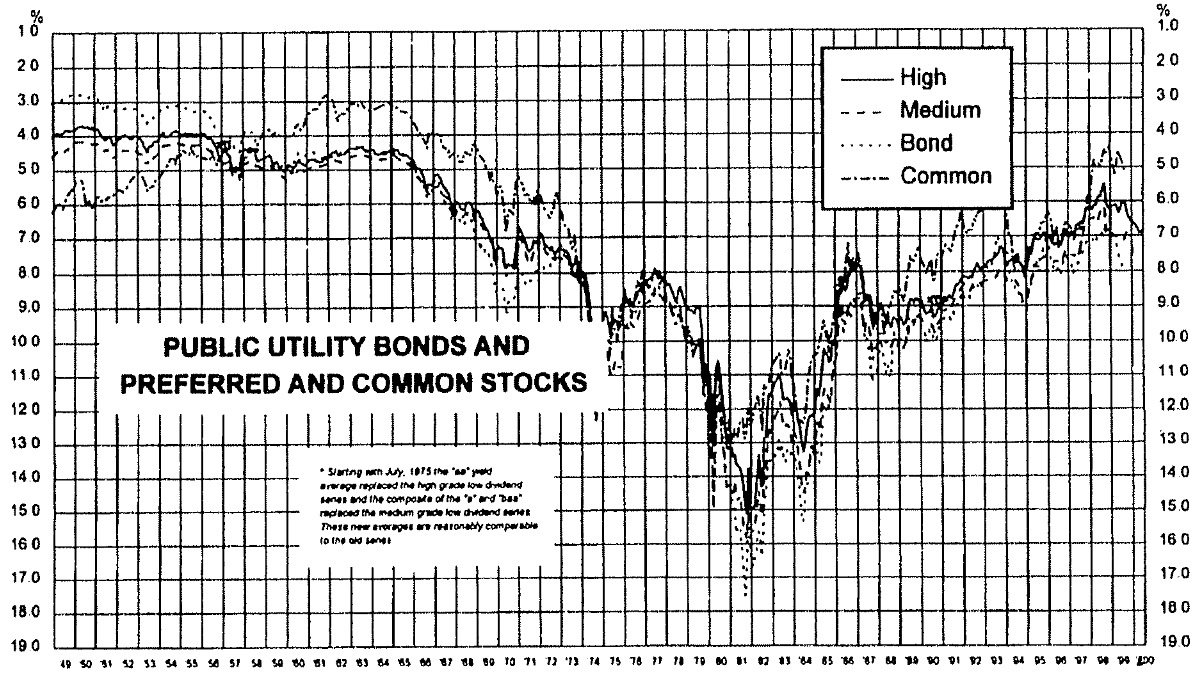
Stocks Used In Moody's Utility Preferred Stock Averages

"aa" - Rating
Central Illinois Light Co. ($100) $4.64
Central Illinois Light Co. ($100) $4.50
Central Illinois Public Service ($100) $4.00
Central Illinois Public Service ($100) $4.90
Central Illinois Public Service ($100) $4.92
Louisville Gas & Electric Co. ($25) $1.25

"a" - Rating
Alabama Power Capital Trust I ($25) $1.84
Alabama Power Co. ($25) $1.60
Alabama Power Co. ($25) $1.70
Alabama Power Co. ($100) $4.52
Alabama Power Co. ($100) $4.72
Alabama Power Co. ($100) $4.92
Alabama Power Co. ($100) $4.20
Alabama Power Co. ($100) $4.64
Alabama Power Co. ($100) $4.60
Baltimore Gas & Electric ($100) $6.75
Baltimore Gas & Electric ($100) $6.97
Baltimore Gas & Electric ($100) $6.99
Baltimore Gas & Electric ($100) $6.70
Baltimore Gas & Electric ($100) $7.13
Baltimore Gas & Electric ($100) $7.85
Baltimore Gas & Electric ($100) $7.78
Baltimore Gas & Electric ($100) $8.63
Carolina Power & Light Co. ($100) $4.20
Carolina Power & Light Co. ($100) $5.00
MidAmerican Energy Co. ($100) $7.80
MidAmerican Energy Financing I ($25) $1.99
Northern States Power Co. (MN) ($100) $4.08
Northern States Power Co. (MN) ($100) $4.10
Northern States Power Co. (MN) ($100) $4.11
Northern States Power Co. (MN) ($100) $4.16
Northern States Power Co. (MN) ($100) $3.60
Pacific Gas & Electric Co. ($25) $1.76

"baa" - Rating
Appalachian Power Co. ($100) $6.85
Arizona Public Service Co. ($25) $1.10
Arizona Public Service Co. ($25) $1.81
Arizona Public Service Co. ($50) $2.50
Arizona Public Service Co. ($50) $2.40
Arizona Public Service Co. ($50) $3.25
Arizona Public Service Co. ($50) $2.36
Arizona Public Service Co. ($100) $6.00
Atlantic City Electric Co. ($100) $4.75
Atlantic City Electric Co. ($100) $7.80
Atlantic City Electric Co. ($100) $8.20
Boston Edison Co. ($25) $1.94
Boston Edison Co. ($100) $7.27
Boston Edison Co. ($100) $8.00
Central Hudson Gas & Electric Corp. ($100) $4.75
Duquesne Light Co. ($50) $2.10
Duquesne Light Co. ($50) $2.07
Duquesne Light Co. ($50) $2.05

Duquesne Light Co. ($50) $2.00
Entergy Arkansas Capital I ($25) $2.13
Illinois Power Co. ($50) $2.21
Illinois Power Co. ($50) $2.35
Illinois Power Co. ($50) $2.13
Illinois Power Co. ($50) $2.04
Illinois Power Co. ($50) $3.87
Illinois Power Financing I ($25) $2.00
Minnesota Power & Light Co. ($100) $5.00
Montana Power Capital I ($25) $2.11
Ohio Power Co. ($100) $4.08
Ohio Power Co. ($100) $4.20
Ohio Power Co. ($100) $4.50
Ohio Power Co. ($100) $4.40
PP&L Inc. ($100) $4.50
Public Service Electric & Gas Co. ($25) $1.69



MOODY'S ELECTRIC UTILITY COMMON STOCKS

END-OF-MONTH AVERAGES

MARKET PRICE - WEIGHTED AVERAGE - $ PER SHARE

Year	Aver	Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
2001		199.03	207.83	219.00	224.50	223.80	210.30						
2000	167.69	146.31	131.96	131.86	147.83	149.08	142.71	152.93	163.75	200.12	202.97	215.69	227.09
1999	160.23	169.51	160.83	159.32	167.11	179.81	170.23	165.86	163.69	153.55	155.69	139.85	137.30
1998	161.03	148.60	151.93	160.83	153.95	154.46	159.51	151.14	160.47	168.13	164.59	176.96	181.84
1997	136.36	135.20	134.70	130.70	126.50	129.60	134.10	136.90	131.90	136.40	138.70	145.90	155.73
1996	133.27	145.90	139.60	134.40	127.20	133.00	134.20	123.60	126.70	127.40	133.00	138.20	136.00
1995	130.53	124.10	123.50	119.90	122.90	131.00	129.70	130.30	130.00	137.50	138.00	136.50	142.90
1994	121.60	142.60	133.20	127.00	127.50	118.80	112.80	118.80	119.70	114.40	113.60	114.00	115.50
1993	151.22	144.48	152.96	152.36	150.37	149.20	151.26	155.07	158.79	155.80	153.40	144.20	146.70
1992	137.07	135.87	133.16	131.76	135.72	136.89	135.01	141.92	138.59	138.94	137.75	138.18	141.06
1991	126.97	116.65	121.00	123.29	122.25	120.48	119.19	124.25	127.80	132.77	134.13	137.81	144.02
1990	112.61	116.90	116.81	114.26	107.68	111.55	112.50	113.38	104.90	104.47	114.55	116.56>	117.77
1989	110.45	103.23	99.81	98.64	102.49	107.29	111.25	117.12	113.70	113.73	116.28	119.35	122.52
1988	97.99	102.86	100.38	95.22	91.65	95.42	96.88	96.51	96.27	98.81	101.32	99.67	100.94
1987	105.90	123.06	118.35	113.48	107.10	103.30	105.83	102.44	105.66	102.59	98.39	96.30	94.24
1986	111.11	97.44	106.11	109.01	102.23	104.88	109.23	117.40	125.66	112.15	117.57	117.99	113.66
1985	87.24	80.47	81.05	83.66	85.91	89.32	92.81	87.22	89.43	83.59	88.10	90.39	94.98
1984	71.16	71.08	68.08	66.74	65.95	66.09	66.49	68.12	70.45	74.77	77.05	78.99	80.16
1983	74.04	72.53	73.59	73.79	75.39	75.35	71.73	72.19	72.50	74.88	78.18	76.37	72.03
1982	63.56	57.95	60.16	60.77	63.15	63.23	61.15	59.16	66.63	66.10	66.83	67.34	70.26
1981	55.41	53.19	52.61	54.43	53.43	54.00	56.04	56.33	56.82	54.99	56.01	59.83	57.20
1980	54.80	54.57	49.93	50.16	57.14	58.51	60.08	57.83	56.40	54.51	52.63	51.44	54.42
1979	60.28	63.99	62.14	62.36	58.69	60.35	61.03	61.41	62.05	59.79	55.84	59.27	56.41
1978	63.54	65.23	64.66	64.95	63.46	63.77	63.56	65.39	65.16	64.90	60.10	61.54	59.75
1977	67.55	66.45	64.90	64.84	66.03	67.36	70.23	70.56	67.91	68.53	66.82	68.76	68.19
1976	60.10	60.68	57.82	57.32	57.76	55.35	57.07	58.62	60.91	63.45	61.85	64.11	66.29
1975	51.25	49.60	49.13	47.80	46.99	49.62	55.06	51.58	51.33	49.66	53.19	55.37	55.66
1974	48.26	63.23	63.72	61.31	50.33	47.49	43.43	44.90	39.93	39.01	42.91	41.67	41.17
1973	71.21	79.43	77.54	75.20	74.73	74.69	72.89	69.70	67.87	72.38	68.21	60.95	60.87
1972	80.20	84.18	81.48	80.77	77.94	77.13	75.27	75.11	78.25	78.48	83.36	86.86	83.61
1971	84.16	90.82	87.70	89.49	85.82	81.51	84.95	83.31	79.70	78.81	82.41	79.80	85.56
1970	79.06	80.31	85.35	87.44	80.06	74.91	68.96	74.55	77.17	75.66	74.15	81.54	88.59
1969	94.55	106.49	101.51	99.88	99.64	99.81	94.53	92.47	91.13	86.29	92.25	85.98	84.62
1968	98.37	97.75	97.15	92.66	92.93	92.08	100.10	99.76	99.25	98.46	98.83	107.33	104.04
1967	101.87	108.12	105.18	106.81	108.90	102.58	100.73	103.04	99.63	99.76	93.63	95.92	98.19
1966	102.90	111.34	106.81	105.41	106.33	102.45	99.95	101.03	92.51	94.57	104.92	103.47	105.99
1965	117.08	119.00	118.81	118.85	119.57	118.21	114.22	114.76	115.46	116.95	118.38	115.84	114.86
1964	108.76	103.69	104.23	103.13	104.00	104.11	105.40	110.76	110.86	112.67	115.11	115.62	115.54
1963	102.79	102.52	99.88	101.40	102.94	103.80	102.10	102.44	107.57	105.14	102.53	100.82	102.31
1962	91.50	95.14	97.76	98.87	96.45	86.79	81.74	87.72	90.12	87.42	86.83	92.64	96.49
1961	90.55	80.47	82.66	85.20	85.54	88.57	85.87	88.06	92.73	94.50	99.77	103.91	99.32
1960	69.82	64.67	66.13	66.66	67.30	67.31	71.51	71.12	73.59	70.25	70.27	72.24	76.82
1959	66.35	66.66	67.40	68.12	67.24	66.28	64.25	66.49	67.39	65.69	65.51	65.38	65.77
1958	57.96	53.04	53.27	54.16	56.05	56.78	57.74	58.21	57.20	59.38	61.08	62.18	66.37
1957	49.42	50.05	49.98	49.88	50.37	51.85	48.96	49.60	48.52	47.67	47.15	48.65	50.30
1956	49.62	49.10	49.66	51.38	49.74	49.10	49.55	51.98	50.36	48.42	48.46	48.72	48.96
1955	49.24	46.94	48.59	47.97	49.12	48.54	49.21	51.39	51.43	49.83	48.53	49.90	49.35
1954	44.30	40.87	41.42	42.56	42.91	43.79	43.91	46.67	45.44	45.90	44.18	46.33	47.56
1953	37.80	38.40	38.21	37.81	36.96	37.08	36.02	36.81	37.16	37.20	38.59	39.70	39.61
1952	35.48	34.42	34.41	34.73	33.97	34.57	34.65	35.09	36.15	36.34	36.25	37.36	37.85
1951	32.55	31.86	32.82	31.77	31.78	31.99	31.70	32.67	33.13	32.87	32.94	33.26	33.85
1950	31.23	31.60	31.91	32.08	32.47	33.51	31.07	29.73	30.07	30.58	30.55	30.34	30.81
1949	28.37	27.15	26.93	27.41	27.75	27.62	27.02	28.03	28.76	29.58	29.82	29.81	30.57
1948	27.34	27.32	26.25	26.91	27.05	28.41	28.61	27.88	27.77	27.42	28.41	25.80	26.20
1947	29.53	32.31	31.87	30.53	29.68	29.30	30.39	30.36	30.37	29.76	29.02	25.20	25.60
1946	34.05	35.95	33.70	35.23	35.88	36.62	35.72	35.05	33.07	30.93	31.84	31.86	32.71
1945	26.29	22.35	23.46	22.47	24.41	24.73	25.61	25.71	25.96	28.11	29.92	31.62	31.14
1944	20.90	20.56	20.72	20.52	20.26	20.58	21.81	20.40	21.88	21.24	21.11	20.60	21.09
1943	18.87	15.58	16.63	16.83	18.64	19.53	20.01	19.69	19.33	20.10	20.40	18.65	21.01
1942	12.92	13.81	13.07	12.03	11.41	12.46	12.57	12.44	12.21	12.59	14.18	13.93	14.29
1941	18.16	21.90	21.25	20.45	18.57	17.73	18.22	18.98	18.53	17.87	16.24	14.74	13.45
1940	25.64	28.87	28.45	28.78	28.13	22.55	25.94	25.94	25.46	24.86	24.28	22.14	22.22
1939	28.02	27.65	29.88	25.71	26.15	27.90	26.54	29.89	27.67	28.81	28.83	28.34	28.85
1938	24.27	23.14	23.84	18.93	21.83	21.76	25.36	25.34	23.94	24.12	28.71	26.69	27.55
1937	33.08	42.46	40.71	38.18	35.13	32.68	31.17	36.40	32.89	28.67	27.14	27.26	24.24
1936	40.28	40.72	38.61	38.51	35.16	37.83	38.78	42.52	41.97	41.61	43.71	42.31	41.60
1935	27.20	20.48	17.90	19.77	21.92	24.52	26.83	29.15	30.86	30.25	33.92	34.72	36.06
1934	27.84	34.39	33.44	32.89	31.59	28.75	29.85	24.97	25.28	25.29	23.45	23.08	21.06
1933	34.37	37.98	30.47	26.70	33.26	39.72	45.79	40.01	39.48	32.02	29.49	28.76	28.73
1932	36.40	42.50	45.23	39.84	33.67	24.00	24.04	32.19	37.37	43.38	38.40	36.76	39.42
1931	69.80	80.32	91.34	89.01	78.91	70.52	79.10	73.52	74.84	50.46	55.38	50.99	43.23

DIVIDEND RATE - WEIGHTED AVERAGE - $ PER SHARE

Year	Aver	Jan	Feb.	Mar	Apr.	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2001		7.83	8.59	8.86	8.68	8.69	8.69						
2000	8.27	8.19	8.22	7.89	7.90	7.87	7.83	8.15	7.76	8.78	8.75	9.23	8.71
1999	8.10	8.15	8.09	8.35	8.17	8.16	8.00	8.01	8.13	8.07	8.09	7.97	8.06
1998	7.83	9.06	7.85	7.64	7.69	7.64	7.67	7.67	7.61	7.51	7.59	8.01	8.01
1997	9.06	9.06	9.06	9.06	9.06	9.06	9.06	9.06	9.06	9.06	9.06	9.06	9.06
1996	9.06	9.06	9.06	9.06	9.06	9.06	9.06	9.06	9.06	9.06	9.06	9.06	9.06
1995	9.02	9.01	9.01	9.01	9.01	9.01	9.01	9.01	9.01	9.01	9.06	9.06	9.06
1994	8.96	8.94	8.94	8.94	8.95	8.96	8.96	8.96	8.96	8.96	9.01	9.01	9.01
1993	8.99	8.92	8.96	8.96	8.97	8.98	9.00	9.00	9.00	9.00	9.04	9.05	9.04
1992	9.05	9.12	9.16	9.16	9.17	9.19	9.22	9.23	9.23	8.76	8.79	8.80	8.82
1991	8.95	8.87	8.91	8.91	8.92	8.92	8.95	8.95	8.95	8.95	8.99	9.00	9.02
1990	8.79	8.99	9.03	9.03	8.70	8.69	8.72	8.72	8.72	8.72	8.72	8.73	8.76
1989	8.82	8.76	8.78	8.78	8.80	8.81	8.84	8.84	8.84	8.84	8.84	8.85	8.85
1988	8.87	9.17	9.17	8.95	8.98	8.99	9.03	8.69	8.69	8.69	8.69	8.69	8.71
1987	9.12	9.09	9.09	9.09	9.12	9.13	9.13	9.13	9.13	9.14	9.14	9.14	9.12
1986	8.89	8.80	8.80	8.80	8.84	8.89	8.89	8.94	8.94	8.94	8.95	8.96	8.97
1985	8.61	8.44	8.46	8.48	8.52	8.61	8.66	8.66	8.66	8.69	8.69	8.70	8.71
1984	8.26	8.11	8.12	8.14	8.17	8.25	8.30	8.31	8.31	8.34	8.34	8.35	8.37
1983	7.87	7.73	7.75	7.76	7.80	7.86	7.86	7.87	7.87	7.97	7.97	7.98	8.00
1982	7.43	7.20	7.22	7.31	7.32	7.42	7.44	7.48	7.48	7.55	7.56	7.57	7.64
1981	6.99	6.83	6.85	6.85	6.87	6.91	6.96	6.99	6.99	7.13	7.13	7.15	7.16
1980	6.58	6.45	6.52	6.52	6.53	6.56	6.58	6.59	6.60	6.65	6.65	6.67	6.67
1979	6.22	6.07	6.07	6.16	6.16	6.17	6.20	6.22	6.26	6.31	6.32	6.33	6.34
1978	5.81	5.76	5.77	5.77	5.78	5.78	5.79	5.80	5.80	5.83	5.83	5.87	5.98
1977	5.54	5.39	5.30	5.51	5.52	5.54	5.55	5.57	5.57	5.57	5.58	5.59	5.68
1976	5.18	5.11	5.13	5.14	5.15	5.16	5.18	5.18	5.18	5.20	5.22	5.25	5.25
1975	4.97	4.96	4.96	4.96	4.96	4.96	4.96	4.97	4.97	4.97	4.97	4.98	4.99
1974	4.83	5.08	5.09	5.12	4.56	4.57	4.57	4.82	4.82	4.82	4.83	4.83	4.83
1973	5.01	4.95	4.98	4.99	4.99	4.99	5.00	5.01	5.02	5.03	5.03	5.03	5.04
1972	4.87	4.83	4.83	4.86	4.86	4.86	4.86	4.86	4.86	4.89	4.89	4.90	4.92
1971	4.77	4.74	4.74	4.75	4.78	4.78	4.78	4.78	4.78	4.78	4.78	4.79	4.81
1970	4.70	4.64	4.64	4.70	4.70	4.70	4.71	4.71	4.71	4.71	4.71	4.72	4.73
1969	4.61	4.58	4.58	4.59	4.59	4.61	4.61	4.61	4.62	4.62	4.62	4.63	4.63
1968	4.50	4.44	4.45	4.46	4.48	4.48	4.48	4.50	4.50	4.55	4.55	4.56	4.58
1967	4.34	4.18	4.20	4.27	4.27	4.32	4.38	4.39	4.39	4.39	4.40	4.41	4.44
1966	4.11	4.03	4.03	4.08	4.08	4.09	4.10	4.12	4.14	4.14	4.14	4.15	4.18
1965	3.86	3.73	3.73	3.80	3.80	3.80	3.83	3.84	3.88	3.90	3.96	3.99	4.02
1964	3.43	3.33	3.34	3.38	3.38	3.38	3.38	3.39	3.46	3.48	3.49	3.49	3.68
1963	3.21	3.07	3.10	3.10	3.16	3.16	3.21	[illegible]	3.23	3.30	3.30	3.32	3.33
1962	2.97	2.86	2.86	2.91	2.91	2.97	2.98	2.98	2.99	3.02	3.03	3.05	3.07
1961	2.81	2.74	2.75	2.77	2.79	2.79	2.80	2.81	2.83	2.83	2.84	2.85	2.86
1960	2.68	2.67	2.67	2.67	2.67	2.67	2.67	2.68	2.68	2.69	2.69	2.71	2.74
1959	2.61	2.59	2.59	2.59	2.60	2.60	2.60	2.60	2.62	2.63	2.63	2.64	2.64

1958	2.50	2.46	2.46	2.46	2.50	2.50	2.50	2.51	2.51	2.51	2.51	2.52	2.57
1957	2.43	2.40	2.41	2.42	2.43	2.43	2.43	2.42	2.42	2.44	2.44	2.45	2.46
1956	2.32	2.27	2.28	2.32	2.32	2.32	2.32	2.32	2.32	2.32	2.33	2.37	2.37
1955	2.21	2.14	2.14	2.18	2.18	2.21	2.23	2.23	2.23	2.24	2.24	2.27	2.27
1954	2.13	2.09	2.11	2.13	2.13	2.13	2.13	2.13	2.13	2.13	2.13	2.13	2.14
1953	2.01	1.93	1.94	1.95	1.96	1.98	2.01	2.01	2.07	2.07	2.07	2.09	2.09
1952	1.91	1.90	1.89	1.91	1.91	1.91	1.91	1.91	1.92	1.92	1.92	1.92	1.92
1951	1.88	1.85	1.85	1.86	1.87	1.87	1.87	1.87	1.88	1.90	1.90	1.90	1.90
1950	1.76	1.69	1.70	1.70	1.71	1.74	1.74	1.78	1.78	1.78	1.84	1.85	1.85
1949	1.66	1.63	1.63	1.63	1.66	1.66	1.67	1.67	1.66	1.68	1.68	1.68	1.68
1948	1.60	1.58	1.58	1.59	1.59	1.59	1.59	1.59	1.59	1.61	1.61	1.61	1.63
1947	1.56	1.49	1.55	1.55	1.56	1.56	1.57	1.58	1.58	1.58	1.58	1.58	1.58
1946	1.43	1.38	1.40	1.42	1.42	1.41	1.43	1.43	1.45	1.45	1.46	1.47	1.48
1945	1.30	1.24	1.25	1.26	1.26	1.27	1.28	1.30	1.32	1.34	1.36	1.35	1.37
1944	1.31	1.30	1.30	1.31	1.32	1.28	1.29	1.30	1.30	1.31	1.34	1.35	1.35
1943	1.28	1.28	1.28	1.24	1.24	1.24	1.23	1.23	1.29	1.31	1.33	1.33	1.46
1942	1.26	1.27	1.27	1.27	1.27	1.27	1.25	1.24	1.24	1.23	1.23	1.24	1.28
1941	1.44	1.51	1.51	1.51	1.51	1.51	1.52	1.45	1.46	1.45	1.33	1.27	1.27
1940	1.54	1.52	1.52	1.52	1.54	1.54	1.54	1.54	1.54	1.54	1.55	1.58	1.57
1939	1.48	1.44	1.44	1.46	1.46	1.46	1.50	1.50	1.50	1.51	1.51	1.51	1.51
1938	1.50	1.65	1.65	1.54	1.47	1.42	1.48	1.48	1.48	1.46	1.46	1.49	1.45
1937	1.74	1.78	1.78	1.78	1.76	1.76	1.77	1.77	1.76	1.69	1.69	1.70	1.68
1936	1.48	1.33	1.33	1.33	1.33	1.33	1.35	1.51	1.53	1.60	1.64	1.69	1.78
1935	1.32	1.36	1.36	1.34	1.34	1.31	1.31	1.29	1.29	1.29	1.28	1.29	1.33
1934	1.60	1.73	1.73	1.73	1.58	1.58	1.55	1.55	1.58	1.58	1.58	1.58	1.42
1933	1.95	2.21	2.21	2.09	1.99	1.99	1.97	1.97	1.90	1.82	1.75	1.75	1.75
1932	2.63	3.19	3.12	3.03	2.96	2.95	2.52	2.38	2.38	2.27	2.27	2.27	2.22
1931	3.47	3.65	3.69	3.66	3.55	3.54	3.53	3.52	3.49	3.39	3.22	3.21	3.20

YIELD - %

Year	Aver	Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul	Aug.	Sep.	Oct.	Nov.	Dec.
2001		3.93	4.13	4.05	3.87	3.88	4.13	...	...	...	...	...	...
2000	8.07	5.59	6.23	5.99	5.34	5.28	5.49	5.33	4.74	4.39	4.31	4.28	3.84
1999	5.09	4.81	5.03	5.24	4.89	4.54	4.70	4.83	4.97	5.25	5.19	5.70	5.87
1998	4.88	6.10	5.17	4.75	5.00	4.95	4.81	5.07	4.74	4.47	4.61	4.53	4.40
1997	6.66	6.70	6.73	6.93	7.16	6.99	6.76	6.62	6.87	6.64	6.53	6.21	5.82
1996	6.81	6.21	6.49	6.74	7.12	6.81	6.75	7.33	7.15	7.11	6.81	6.56	6.67
1995	6.93	7.26	7.30	7.52	7.33	6.88	6.95	6.92	6.93	6.55	6.57	6.64	6.34
1994	7.41	6.27	6.71	7.04	7.02	7.54	7.94	7.54	7.49	7.83	7.93	7.90	7.80
1993	5.95	6.17	5.86	5.88	5.97	6.02	5.95	5.80	5.67	5.78	5.87	6.27	6.16
1992	6.61	6.71	6.88	6.95	6.76	6.71	6.83	[R]6.50	[R]6.66	6.30	6.38	6.37	6.25
1991	7.07	7.60	7.36	7.23	7.30	7.40	7.51	7.20	7.00	6.74	6.70	6.53	6.26
1990	7.82	7.69	7.73	7.90	8.08	7.79	7.75	7.69	8.31	8.35	7.61	7.49	7.44
1989	8.02	8.49	8.80	8.90	8.59	8.21	7.95	7.55	7.77	7.77	7.60	7.42	7.22
1988	9.06	8.92	9.14	9.40	9.80	9.42	9.32	9.00	9.03	8.79	8.58	8.72	8.63
1987	8.67	7.39	7.68	8.01	8.52	8.84	8.63	8.91	8.64	8.91	9.29	9.49	9.68
1986	8.00	9.03	8.29	8.07	8.65	8.48	8.14	7.61	7.11	7.97	7.61	7.59	7.89
1985	9.89	10.49	10.44	10.14	9.92	9.64	9.33	9.93	9.68	10.40	9.86	9.62	9.17
1984	11.61	11.41	11.93	12.20	12.39	12.48	12.48	12.20	11.84	11.15	10.82	10.57	10.44
1983	10.63	10.66	10.53	10.52	10.35	10.43	10.96	10.90	10.86	10.64	10.19	10.45	11.11
1982	11.69	12.42	12.00	12.03	11.59	11.73	12.17	12.64	11.23	11.42	11.31	11.24	10.87
1981	12.62	12.84	13.02	12.59	12.86	12.80	12.42	12.41	12.30	12.97	12.73	11.95	12.52
1980	12.01	11.82	13.06	13.00	11.43	11.21	10.95	11.40	11.70	12.20	12.64	12.97	12.26
1979	10.32	9.49	9.77	9.88	10.50	10.22	10.16	10.13	10.09	10.55	11.32	10.68	11.24
1978	9.14	8.83	8.92	8.88	9.11	9.06	9.11	8.87	8.90	8.98	9.70	9.54	10.01
1977	8.20	8.11	8.32	8.50	8.36	8.22	7.90	7.89	8.20	8.13	8.35	8.13	8.33
1976	8.62	8.42	8.87	8.97	8.92	9.32	9.08	8.84	8.50	8.20	8.44	8.19	7.92
1975	9.70	10.00	10.10	10.38	10.56	10.00	9.01	9.64	9.68	10.01	9.34	8.99	8.97
1974	10.01	8.03	7.99	8.35	9.06	9.62	10.52	10.74	12.07	12.36	11.26	11.59	11.73
1973	7.04	6.23	6.42	6.64	6.68	6.68	6.86	7.19	7.40	6.95	7.37	8.25	8.28
1972	6.07	5.74	5.93	6.02	6.24	6.30	6.46	6.47	6.24	6.23	5.87	5.64	5.88
1971	5.70	5.22	5.40	5.29	5.56	5.86	5.77	5.74	5.96	6.03	5.80	6.09	5.62
1970	5.94	5.78	5.44	5.38	5.87	6.27	6.83	6.32	6.10	6.23	6.35	5.79	5.34
1969	4.88	4.30	4.51	4.60	4.61	4.62	4.88	4.99	5.07	5.35	5.01	5.38	5.47
1968	4.57	4.54	4.58	4.81	4.82	4.87	4.48	4.51	4.53	4.62	4.60	4.25	4.40
1967	4.26	3.87	3.99	4.00	3.92	4.21	4.35	4.26	4.41	4.40	4.70	4.60	4.52
1966	3.99	3.62	3.77	3.87	3.84	3.99	4.10	4.08	4.08	4.38	3.95	4.01	3.94
1965	3.30	3.13	3.14	3.20	3.18	3.21	3.35	3.35	3.36	3.33	3.35	3.44	3.50
1964	3.15	3.21	3.20	3.28	3.25	3.25	3.21	3.06	3.12	3.09	3.03	3.02	3.19
1963	3.12	2.99	3.10	3.06	3.07	3.04	3.14	3.13	3.00	3.14	3.22	3.29	3.25
1962	3.25	3.01	2.93	2.94	3.02	3.42	3.65	3.40	3.32	3.45	3.49	3.29	3.18
1961	3.10	3.40	3.33	3.25	3.26	3.15	3.26	3.19	3.05	2.99	2.85	2.74	2.88
1960	3.81	4.13	4.04	4.01	3.97	3.97	3.73	3.77	3.64	3.83	3.83	3.75	3.57
1959	3.94	3.89	3.84	3.80	3.87	3.92	4.05	3.91	3.89	4.00	4.01	4.04	4.01
1958	4.33	4.64	4.62	4.54	4.46	4.40	4.33	4.31	4.39	4.23	4.11	4.05	3.87
1957	4.92	4.80	4.82	4.85	4.82	4.69	4.96	4.88	4.99	5.12	5.17	5.04	4.89
1956	4.68	4.62	4.59	4.52	4.66	4.73	4.68	4.46	4.61	4.79	4.81	4.86	4.84
1955	4.50	4.56	4.40	4.54	4.44	4.55	4.53	4.34	4.34	4.50	4.62	4.55	4.60
1954	4.81	5.11	5.09	5.00	4.96	4.86	4.85	4.56	4.69	4.64	4.82	4.60	4.50
1953	5.33	5.03	5.08	5.16	5.30	5.34	5.58	5.46	5.57	5.56	5.36	5.26	5.28
1952	5.39	5.52	5.49	5.50	5.62	5.53	5.51	5.44	5.31	5.28	5.30	5.14	5.07
1951	5.77	5.81	5.64	5.85	5.88	5.85	5.90	5.72	5.67	5.78	5.77	5.71	5.61
1950	5.66	5.35	5.33	5.30	5.27	5.19	5.60	5.99	5.92	5.82	6.02	6.10	6.00
1949	5.86	6.00	6.05	5.95	5.98	6.01	6.18	5.96	5.77	5.68	5.63	5.64	5.50
1948	5.85	5.78	6.02	5.91	5.88	5.60	5.56	5.70	5.73	5.87	5.67	[illegible]	6.22
1947	5.32	4.61	4.86	5.08	5.26	5.32	5.17	5.20	5.20	5.31	5.44	[illegible]	6.17
1946	4.23	3.84	4.15	4.03	3.96	3.85	4.00	4.08	4.38	4.69	4.59	4.61	4.52
1945	4.99	5.55	5.33	5.61	5.16	5.14	5.00	5.06	5.08	4.77	4.55	4.27	4.40
1944	6.28	6.32	6.27	6.38	6.52	6.22	5.91	6.37	5.94	6.17	6.35	6.55	6.40
1943	6.85	8.22	7.70	7.37	6.65	6.35	6.15	6.25	6.67	6.52	6.52	7.13	6.66
1942	9.76	9.20	9.72	10.56	11.13	10.19	9.94	9.97	10.16	9.77	8.67	8.90	8.96
1941	8.02	6.89	7.11	7.38	8.33	8.52	8.34	7.64	7.88	8.11	8.19	8.62	9.44
1940	6.07	5.26	5.34	5.28	5.47	6.83	5.94	5.94	6.05	6.19	6.38	7.14	7.07
1939	5.30	5.21	4.82	5.68	5.58	5.23	5.65	5.02	5.42	5.21	5.24	5.33	5.23
1938	6.27	7.13	6.92	8.14	6.73	6.53	5.84	5.84	6.18	6.05	5.09	5.58	5.26
1937	5.40	4.19	4.37	4.66	5.01	5.39	5.68	4.86	5.35	5.89	6.23	6.24	6.93
1936	3.67	3.27	3.44	3.45	3.78	3.52	3.48	3.55	3.65	3.85	3.75	3.99	4.28
1935	5.12	6.64	7.60	6.78	6.11	5.34	4.88	4.43	4.18	4.26	3.77	3.72	3.69
1934	5.85	5.03	5.17	5.26	5.00	5.50	5.19	6.21	6.25	6.25	6.74	6.85	6.74
1933	5.81	5.82	7.25	7.83	5.98	5.01	4.30	4.92	4.81	5.68	5.93	6.08	6.09
1932	7.52	7.51	6.90	7.61	8.79	12.29	10.48	7.39	6.37	5.23	5.91	6.18	5.63
1931	5.20	4.54	4.04	4.11	4.50	5.02	4.46	4.79	4.66	6.72	5.81	6.30	7.10

Note ☐ Revised

EARNINGS - WEIGHTED AVERAGE - $ PER SHARE

Year	Year	1Q	2Q	3Q	4Q						
2000	8.36	4.31	3.42	6.06	8.36	1980	8.98	8.69	8.58	8.75	8.98
1999	8.21	8.30	10.80	12.79	8.21	1979	8.95	8.87	8.88	9.20	8.95
1998	8.79	4.87	3.74	5.62	8.79	1978	8.59	8.27	8.37	8.36	8.59
1997	4.81	10.30	9.80	9.00	4.81	1977	8.64	8.89	8.91	8.90	8.64
1996	10.72	13.37	12.82	10.66	10.72	1976	8.15	7.81	7.64	7.86	8.15
1995	13.41	10.61	11.12	13.25	13.41	1975	7.77	7.70	7.76	7.80	7.77
1994	10.23	8.07	8.13	8.18	10.23	1974	7.63	7.15	7.22	7.53	7.63
1993	6.53	11.12	10.86	11.13	6.53	1973	7.55	7.78	7.63	7.60	7.55
1992	11.03	10.30	9.98	9.73	11.03	1972	7.73	7.27	7.53	7.72	7.73
1991	10.06	9.20	10.52	10.89	10.06	1971	7.14	6.91	6.88	7.10	7.14
1990	9.03	10.43	9.25	8.92	9.03	1970	6.89	6.90	6.90	6.82	6.89
1989	11.07	7.97	8.32	8.54	11.07	1969	6.92	6.74	6.81	6.89	6.92
1988	7.55	11.27	10.70	10.60	7.55	1968	6.67	6.78	6.67	6.73	6.67
1987	11.45	12.86	12.63	12.36	11.45	1967	6.67	6.37	6.42	6.53	6.67
1986	13.13	12.40	12.72	13.17	13.13	1966	6.30	6.03	6.08	6.19	6.30
1985	12.53	12.66	12.65	12.67	12.53	1965	5.92	5.51	5.68	5.82	5.92
1984	12.67	12.35	12.56	12.18	12.67	1964	5.41	5.02	5.13	5.26	5.41
1983	11.88	10.87	10.87	11.49	11.88	1963	4.99	4.81	4.87	4.91	4.99
1982	10.90	10.52	10.80	11.06	10.90	1962	4.73	4.45	4.50	4.57	4.73
1981	10.16	9.35	9.59	10.11	10.16	1961	4.33	4.17	4.21	4.27	4.33
						1960	4.12	3.89	3.99	4.08	4.12

1959	3.82	3.69	3.75	3.77	3.82	1944	1.75	1.60	1.68	1.72	1.75
1958	3.63	3.50	3.53	3.60	3.63	1943	1.55	1.45	1.55	1.63	1.55
1957	3.41	3.36	3.31	3.35	3.41	1942	1.40	1.46	1.33	1.32	1.40
1956	3.35	3.27	3.32	3.35	3.35	1941	1.59	1.75	1.67	1.61	1.59
1955	3.21	3.03	3.08	3.14	3.21	1940	1.81	1.91	1.90	1.83	1.81
1954	2.94	2.81	2.85	2.88	2.94	1939	1.82	1.55	1.69	1.79	1.82
1953	2.78	2.70	2.79	2.85	2.78	1938	1.42	1.87	1.63	1.48	1.42
1952	2.62	2.47	2.49	2.61	2.62	1937	2.06	2.04	2.13	2.14	2.06
1951	2.44	2.60	2.53	2.44	2.44	1936	2.01	1.67	1.78	1.89	2.01
1950	2.62	2.52	2.58	2.54	2.62	1935	1.54	1.23	1.24	1.37	1.54
1949	2.36	2.24	2.28	2.37	2.36	1934	1.22	1.50	1.46	1.32	1.22
1948	2.22	2.14	2.08	2.15	2.22	1933	1.56	2.04	1.82	1.75	1.56
1947	2.16	2.12	2.15	2.12	2.16	1932	2.30	3.48	3.11	2.73	2.30
1946	2.19	1.97	2.05	2.14	2.19	1931	3.80	4.34	4.24	4.07	3.80
1945	1.72	1.76	1.70	1.71	1.72						

Note: Quarterly earnings are for the 12 months ended Mar. 31, June 30, Sept. 30 and Dec. 31.

[1]PRICE EARNING RATIO

Year	Aver.	Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
2000	26.13	17.50	15.78	15.77	34.30	34.59	33.11	25.24	27.02	33.02	24.28	25.80	27.16
1999	17.65	20.42	19.38	19.20	15.47	16.65	15.76	12.97	12.79	12.01	18.96	17.03	16.72
1998	27.46	41.16	41.30	42.65	26.89	28.55	29.92	18.72	20.13	20.69	18.72	20.13	20.69
1997	16.87	13.13	13.08	12.69	12.91	13.22	13.68	15.21	14.66	15.16	28.84	30.33	32.38
1996	12.43	10.91	10.44	10.05	9.92	10.37	10.47	11.59	11.89	11.95	12.41	12.89	12.69
1995	10.86	11.70	11.64	11.30	11.05	11.78	11.66	9.83	9.81	10.38	10.29	10.18	10.66
1994	11.9	17.7	16.5	15.7	15.7	14.6	13.9	14.5	14.6	14.0	11.1	11.1	11.3
1993	23.2	13.0	13.8	13.7	13.8	13.7	13.9	13.9	14.3	14.0	23.5	22.1	22.5
1992	12.4	13.2	12.9	12.8	13.6	13.7	13.5	14.6	14.2	14.3	12.5	12.5	12.8
1991	12.6	12.7	13.2	13.4	11.6	11.5	11.3	13.9	11.7	12.2	13.3	13.7	14.3
1990	12.5	11.2	11.2	11.0	11.6	12.1	12.2	12.7	11.8	11.7	.27	12.9	13.0
1989	10.0	13.0	12.5	12.4	12.5	13.1	13.5	13.7	13.3	13.3	10.5	10.8	11.1
1988	12.9	9.1	8.9	8.4	8.6	8.9	9.1	9.1	9.1	9.3	13.4	13.2	13.4
1987	9.2	9.6	9.2	8.8	8.5	8.2	8.4	8.3	8.5	8.3	8.6	8.4	8.2
1986	8.5	7.9	8.6	8.8	8.0	8.2	8.6	8.9	9.5	8.5	9.0	9.0	8.7
1985	7.0	6.3	6.4	6.6	6.8	7.1	7.3	7.0	7.1	6.6	7.0	7.2	7.6
1984	5.6	5.8	5.5	5.4	5.3	5.3	5.3	5.5	5.6	6.0	6.1	6.2	6.3
1983	6.2	6.6	6.7	6.8	6.9	6.9	6.6	6.5	6.4	6.5	6.9	6.6	6.1
1982	5.8	5.6	5.8	5.8	6.0	5.9	5.7	5.4	6.1	6.0	6.1	6.1	6.4
1981	5.5	5.8	5.7	5.8	5.7	5.7	5.8	5.8	5.7	5.4	5.5	5.9	5.6
1980	6.1	6.2	5.7	5.8	6.6	6.8	7.0	6.7	6.5	6.2	6.0	5.8	6.1
1979	6.8	7.4	7.1	7.0	6.6	6.8	6.9	6.8	6.8	6.5	6.1	6.6	6.3
1978	7.4	7.7	7.7	7.9	7.6	7.6	7.6	7.8	7.8	7.8	7.1	7.2	7.0
1977	7.8	7.9	7.5	7.3	7.4	7.6	7.9	7.9	7.6	7.7	7.6	7.9	7.9
1976	7.4	7.8	7.4	7.3	7.5	7.2	7.5	7.6	7.8	8.1	7.7	8.0	8.1
1975	6.6	6.5	6.4	6.2	6.1	6.4	7.1	6.6	6.6	6.4	6.8	7.1	7.2
1974	6.3	8.5	8.8	8.6	7.0	6.6	6.0	6.1	5.4	5.2	5.7	5.5	5.4
1973	9.4	10.2	10.0	9.7	9.7	9.7	9.6	9.1	8.9	9.5	9.0	8.1	8.1
1972	10.4	11.7	11.3	11.1	10.6	10.4	10.0	9.9	10.2	10.2	10.8	11.2	10.8
1971	11.8	13.2	12.7	13.0	12.4	11.8	12.3	12.0	11.4	11.1	11.6	11.2	12.0
1970	11.5	11.6	12.4	12.7	11.6	10.9	10.0	10.9	11.3	11.1	10.8	11.9	12.9
1969	13.7	15.8	15.0	14.7	14.6	14.7	13.9	13.5	13.3	12.5	13.4	12.4	12.2
1968	14.8	14.6	14.4	13.7	13.9	13.8	15.0	14.9	14.8	14.6	14.7	16.0	15.5
1967	15.3	17.1	16.6	16.8	17.1	16.0	15.7	16.0	15.3	15.3	14.2	14.5	14.7
1966	16.3	18.7	17.8	17.5	17.6	16.9	16.4	16.5	15.0	15.3	16.8	16.5	16.8
1965	19.8	21.8	21.7	21.6	21.5	21.0	20.1	20.0	20.0	20.1	20.2	19.7	19.4
1964	20.1	20.7	20.8	20.5	20.6	20.5	20.5	21.4	21.2	21.4	21.7	21.6	21.4
1963	20.6	21.5	20.9	21.1	21.3	21.4	21.0	20.9	22.0	21.4	20.8	20.3	20.5
1962	19.3	21.8	22.2	19.9	21.6	19.4	18.2	19.4	19.8	19.1	18.8	19.8	20.4
1961	20.9	19.5	19.9	20.4	20.4	21.1	20.4	20.8	21.8	22.1	23.3	24.1	22.9
1960	16.9	16.8	17.1	17.1	17.1	17.0	17.9	17.7	18.2	17.2	17.2	17.6	18.6
1959	17.4	18.3	18.4	18.5	18.1	17.8	17.1	17.7	17.9	17.4	17.3	17.2	17.2
1958	16.0	15.4	15.4	15.5	16.0	16.1	16.4	16.4	16.0	16.5	16.9	17.2	18.3
1957	14.5	14.9	14.9	14.8	15.1	15.6	14.8	14.9	14.5	14.2	14.0	14.4	14.8
1956	14.8	15.2	15.3	15.7	15.2	14.9	14.9	15.6	15.1	14.5	14.5	14.5	14.6
1955	15.3	15.8	16.2	15.8	16.1	15.8	16.0	16.6	16.5	15.9	15.3	15.6	15.4
1954	15.1	14.6	14.8	15.1	15.2	15.4	15.4	16.3	15.8	15.9	15.2	15.9	16.2
1953	13.6	14.5	14.4	14.0	13.5	13.4	12.9	13.1	13.1	13.1	13.6	14.1	14.2
1952	14.4	14.0	14.0	14.1	13.8	13.9	13.9	13.9	14.1	13.9	13.9	14.3	14.4
1951	13.3	12.2	12.6	12.2	12.3	12.5	12.5	13.1	13.4	13.5	13.5	13.6	13.9
1950	11.9	13.1	12.9	12.7	12.8	13.1	12.0	11.6	11.8	12.0	11.9	11.7	11.8
1949	12.0	12.2	12.1	12.2	12.3	12.2	11.9	12.1	12.3	12.5	12.6	12.6	13.0
1948	12.3	12.6	12.2	12.6	12.8	13.5	13.8	13.2	13.0	12.8	13.1	11.8	11.8
1947	13.7	15.0	14.9	14.4	13.9	13.7	14.1	14.2	14.3	14.0	13.6	11.7	11.9
1946	15.5	20.0	17.9	17.9	17.9	18.1	17.4	16.9	15.7	14.5	14.7	14.6	14.9
1945	15.3	12.8	13.3	12.8	14.0	14.4	15.1	15.1	15.2	16.4	17.5	18.4	18.1
1944	11.9	13.1	13.0	12.8	12.4	12.4	13.0	12.0	12.8	12.3	12.2	11.8	12.1
1943	12.2	11.0	11.6	11.6	12.6	12.9	12.9	12.5	12.1	12.3	12.8	11.9	13.6
1942	9.2	9.0	8.7	8.2	8.0	9.0	9.5	9.4	9.3	9.5	10.5	10.2	10.2
1941	11.4	12.2	12.0	11.7	10.7	10.4	10.9	11.5	11.4	11.1	10.1	9.2	8.5
1940	14.2	15.6	15.1	15.1	14.7	11.9	13.7	13.9	13.8	13.6	13.3	12.2	12.3
1939	15.4	18.8	19.8	16.6	16.4	17.0	15.7	17.3	15.7	16.1	16.0	15.7	15.9
1938	17.1	11.6	12.2	10.1	12.2	12.7	15.6	16.0	15.6	16.3	19.7	18.5	19.4
1937	16.1	21.1	20.1	18.7	17.0	15.6	14.6	17.1	15.4	13.4	12.9	13.1	11.8
1936	20.0	25.6	23.7	23.1	20.6	21.6	21.8	23.4	22.7	22.0	22.6	21.5	20.7
1935	17.7	16.8	14.6	16.1	17.8	19.8	21.6	22.6	23.2	22.1	23.9	23.5	23.4
1934	22.8	22.3	22.0	21.9	21.2	19.4	20.4	17.6	18.5	19.2	18.2	18.5	17.3
1933	22.0	17.2	14.3	13.1	16.9	21.0	25.2	22.2	22.3	18.3	17.4	17.8	18.4
1932	15.8	11.5	12.6	11.4	10.0	7.4	7.7	10.8	13.1	15.9	14.5	14.5	16.5
1931	18.4	17.8	20.7	20.5	18.3	16.5	18.7	17.6	18.1	12.4	13.9	13.1	11.4

[1]Monthly Ratio based on end of Month price and 4 Quarter total earnings, latest Quarter estimate. Annual ratio based on Annual average price and annual earnings.

BOOK VALUE AT END OF YEAR - WEIGHTED AVERAGE - $ PER SHARE

Year	Excl Reserves	Incl Reserves	Year	Excl Reserves	Incl Reserves	Year	Excl Reserves	Incl Reserves
2000	166.40	107.04	1982	82.77	104.43	1962	44.37	44.88
1999	128.25	180.83	1981	81.91	101.84	1961	42.20	42.95
1998	92.11	141.36	1980	83.82	102.49	1960	40.25	41.20
1997	103.06	141.97	1979	81.62	99.01	1959	38.79	40.14
1996	98.63	140.71	1978	80.11	94.77	1958	37.21	38.24
1995	93.71	139.71	1977	78.82	92.96	1957	36.32	36.57
1994	93.80	148.67	1976	76.94	89.52	1956	34.53	34.65
1993	92.42	141.22	1975	75.80	85.79	1955	33.26	33.36
1992	93.68	131.59	1974	73.23	79.94	1954	32.16	32.24
1991	91.07	125.21	1973	71.67	76.84	1953		31.54
1990	84.45	117.07	1972	70.41	75.05	1952		31.11
1989	89.41	120.87	1971	66.37	70.24	1951		30.88
1988	88.04	119.07	1970	64.09	67.75	1950		29.65
1987	90.12	122.19	1969	60.54	63.90	1949		28.52
1986	90.35	118.61	1968	57.94	60.97	1948		28.24
1985	87.76	113.12	1967	54.88	57.53	1947		27.92
1984	85.08	111.65	1966	52.23	54.53	1946		27.44
1983	82.90	106.77	1965	50.71	52.68	1945	26.68	
			1964	48.98	50.69			
			1963	46.35	47.91			

Note: Above data revised beginning 1954 to include reserves for deferred federal income taxes arising from liberalized depreciation and the investment credit

Stocks Used in Moody's Electric Utility Average

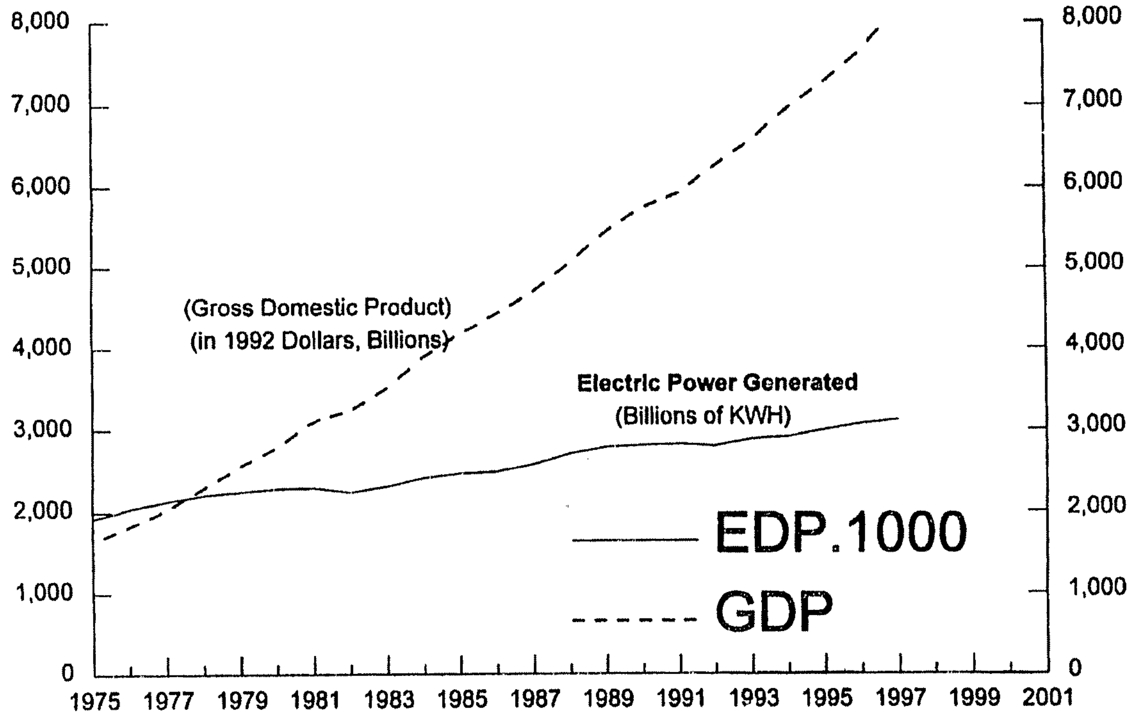
American Electric Power Inc.
Constellation Energy Group Inc.
Progress Energy Inc.
Ch Energy Group Inc.
Cinergy Corp
Consolidated Edison Inc.
DPL Inc.
DTE Energy Co
Dominion Res Inc VA New
Duke Energy Corp.
Energy East Corp.
FirstEnergy Corp.
Reliant Energy Inc.
Idacorp Inc.
Ipalco Enterprises Inc.
Nisource Inc.
Oge Energy Corp
Exelon Corp.
PPL Corp.
Potomac Elec. Power Co.
Public Svc. Enterprise Group
Southern Co.
Teco Energy Inc.
Xcel Energy Inc.

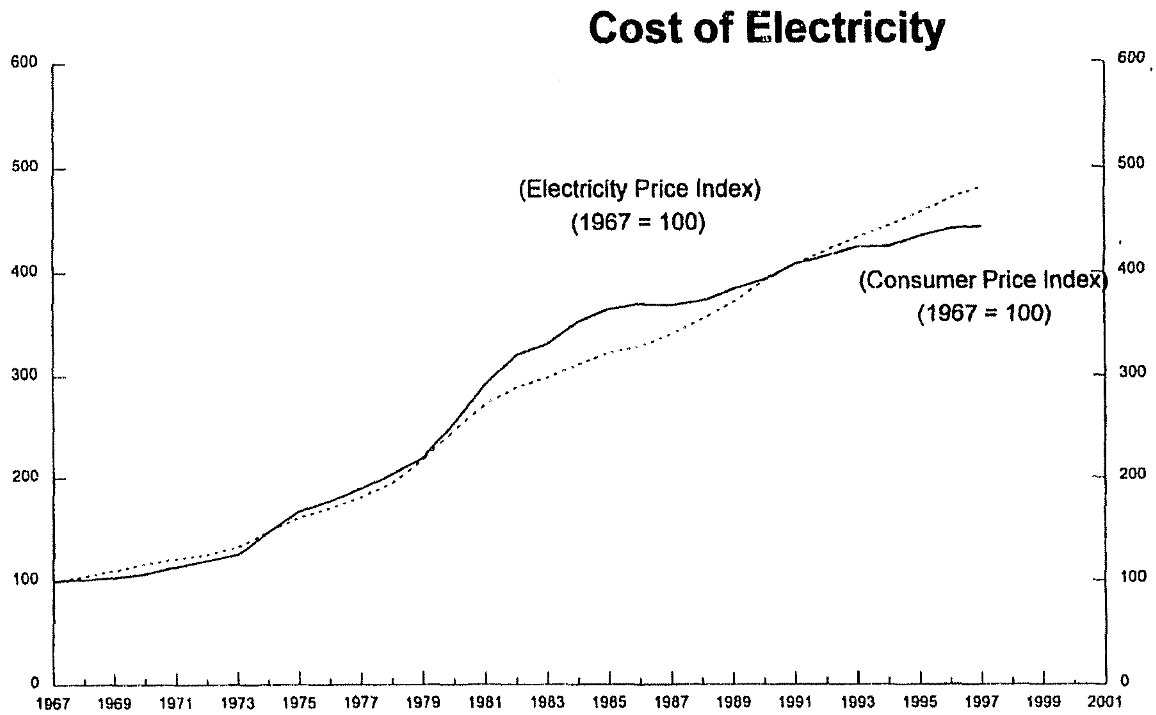
SELECTED STATISTICS ON MOODY'S ELECTRIC UTILITY AVERAGE

					Book Value $ per Share					Capitalization			
	[10]Earnings $ per Share	[1]AFUDC per Share	[10]Dividend $ per Share	[2]Payout Ratio %	[3]Incl. Def Taxes	Excl Def. Taxes	[4]Return on Equity	[5]Int. Cov. incl. AFUDC	[6]Int. Cov. excl. AFUDC	Debt % Lg. Tm.	[7]Sht. Tm.	Pfd %	Common & Surplus %
2000	8.36	2.02	1.57	65.57	166.40	107.04	7.81	13.58	13.55	55.57	10.53	1.52	32.38
1999	8.21	0.12	8.11	98.8	181.78	122.59	6.70	3.33	3.31	45.99	10.4	4.4	39.3
1998	8.79	0.23	7.84	89.2	141.36	92.11	9.56	2.71	2.68	47.8	6.3	3.3	42.7
1997	4.81	0.25	9.06	188.4	141.97	103.06	4.67	2.27	2.24	47.5	3.5	4.1	44.9
1996	10.72	0.24	9.06	84.5	140.71	98.63	10.9	3.15	3.11	46.3	3.1	4.8	45.8
1995	13.41	0.48	9.06	68.0	139.71	93.71	14.3	3.47	3.40	45.9	3.1	5.5	45.5
1994	10.23	0.50	9.01	88.1	148.67	93.80	10.9	3.16	3.09	47.8	2.5	5.8	44.0
1993	6.53	0.70	9.04	138.4	141.22	92.42	7.1	3.05	2.97	50.5	2.8	7.4	39.2
1992	11.03	0.55	8.82	80.0	131.59	93.68	11.8	2.98	2.92	44.6	5.2	6.6	43.6
1991	10.06	0.61	9.02	89.7	125.21	91.07	11.0	2.79	2.76	47.1	4.8	6.6	41.6
1990	9.03	0.87	8.76	97.0	117.07	84.45	10.7	2.63	2.54	46.6	5.5	6.9	41.0
1989	11.07	1.30	8.85	79.9	120.87	89.41	12.4	2.92	2.79	46.7	3.9	7.3	42.1
1988	7.55	1.52	8.71	....	119.07	88.04	8.6	2.63	2.47	47.6	4.8	8.0	39.5
1987	11.45	3.48	9.12	79.7	122.19	90.12	12.7	3.44	3.08	46.3	4.3	7.8	41.6
1986	13.13	4.30	8.97	68.3	118.61	90.35	14.5	3.75	3.32	46.4	3.0	8.6	42.0
1985	12.53	5.35	8.71	69.5	113.12	87.76	14.4	3.33	2.79	46.9	3.2	9.7	40.2
1984	12.67	5.93	8.37	66.1	111.65	85.08	14.9	3.25	2.67	46.3	3.3	10.6	39.8
1983	11.88	6.10	8.00	67.3	106.77	82.90	14.3	3.17	2.57	45.7	3.1	11.5	39.7
1982	10.90	6.11	7.64	70.1	104.43	82.77	13.2	2.49	1.92	46.8	3.5	11.7	38.0
1981	10.16	5.37	7.16	70.5	101.84	81.91	12.4	2.44	1.95	46.3	5.5	11.9	36.3
1980	8.98	5.03	6.67	74.3	102.49	83.82	10.7	2.39	1.89	46.6	4.7	12.7	36.2
1979	8.95	4.19	6.34	70.8	99.01	81.62	11.0	2.57	2.09	47.1	4.3	12.7	35.8
1978	8.59	3.21	5.98	69.6	94.77	80.11	10.7	2.94	2.53	47.6	2.9	12.9	36.6
1977	8.64	2.54	5.68	65.7	92.96	78.82	11.0	2.89	2.54	48.4	2.5	13.1	36.1
1976	8.15	2.57	5.25	64.4	89.52	76.94	10.6	2.75	2.41	49.5	2.9	12.9	34.7
1975	7.77	2.66	4.99	64.2	85.79	75.80	10.3	2.53	2.20	50.2	3.3	12.8	33.7
1974	7.63	2.74	4.83	63.3	79.94	73.23	10.4	2.51	2.16	50.0	5.0	12.7	32.3
1973	7.55	2.41	5.04	66.8	76.84	71.67	10.5	2.79	2.41	50.1	3.7	12.4	33.8
1972	7.73	2.34	4.92	63.6	75.05	70.41	11.0	2.96	2.58	50.6	3.2	12.4	33.8
1971	7.14	1.88	4.81	67.4	70.24	66.37	10.8	2.86	2.53	52.1	2.7	11.7	33.5
1970	6.89	1.48	4.73	68.7	67.75	64.09	10.8	2.98	2.69	52.7	3.1	10.9	33.3
1969	6.92	0.96	4.63	66.9	63.90	60.54	11.4	3.73	3.50	51.5	4.3	9.7	34.5
1968	6.67	0.68	4.58	68.7	60.97	57.94	11.5	4.25	4.06	52.1	2.3	9.9	35.7
1967	6.67	0.52	4.44	66.6	57.53	54.88	12.2	4.66	4.49	51.2	2.3	9.6	36.9
1966	6.30	0.34	4.18	66.3	54.53	52.23	12.1	5.10	4.97	51.2	1.6	9.3	37.9
1965	5.92	0.27	4.02	67.9	52.68	50.71	11.7	5.29	5.18	49.9	1.7	8.8	39.6
1964	5.41	0.22	3.68	68.0	50.69	48.98	11.1	5.30	5.20	50.7	0.8	8.8	39.7
1963	4.99	0.18	3.33	66.7	47.91	46.35	10.8	5.32	5.23	50.9	0.8	9.4	38.9
1962	4.73	0.24	3.07	64.9	44.88	44.37	10.7	5.33	5.22	51.6	0.5	10.0	37.9
1961	4.33	0.25	2.86	66.1	42.95	42.20	10.3	5.25	5.13	51.4	1.5	9.8	37.3
1960	4.12	0.27	2.74	66.5	41.20	40.25	10.2	5.25	5.11	51.7	1.1	10.1	37.1
1959	3.82	0.27	2.64	69.1	40.14	38.79	9.9	5.46	5.31	51.[illegible]	1.2	10.2	37.2
1958	3.63	0.37	2.57	70.8	38.24	37.21	9.8	5.47	5.26	51.6	1.4	10.6	36.4
1957	3.41	0.24	2.46	72.1	36.57	36.32	9.4	5.74	5.58	50.1	1.6	10.9	37.4

[1]Allowance for funds used during construction per year-end weighted share of common stock. [2]Dividends per share divided by earnings per share. [3]Deferred taxes consists of deferred income taxes and deferred investment tax credits. [4]Consists of earnings per share divided by year-end book value per share, excluding deferred income taxes. [5]Consists of net operating income plus federal and state income taxes, deferred investment tax credits, and allowance for funds used during construction, divided by total interest charges. [6]Same as [5] but excluding allowance for funds used during construction. [7]Includes current maturities. [8]Consists of net income plus depreciation, deferred income taxes, deferred investment tax credits, less allowance for funds used during construction and dividends on preferred and common stock. [9]Consists of construction expenditures net of allowance for funds used during construction. [10]Year-end. [11]Third quarter earnings.

Electric Power Generated
Compared With Gross Domestic Product




Cost of Electricity
(Electricity Price Index)
(1967 = 100)
(Consumer Price Index)
(1967 = 100)
600
500
400
300
200
100
0
1967
1969
1971
1973
1975
1977
1979
1981
1983
1985
1987
1989
1991
1993
1995
1997
1999
2001

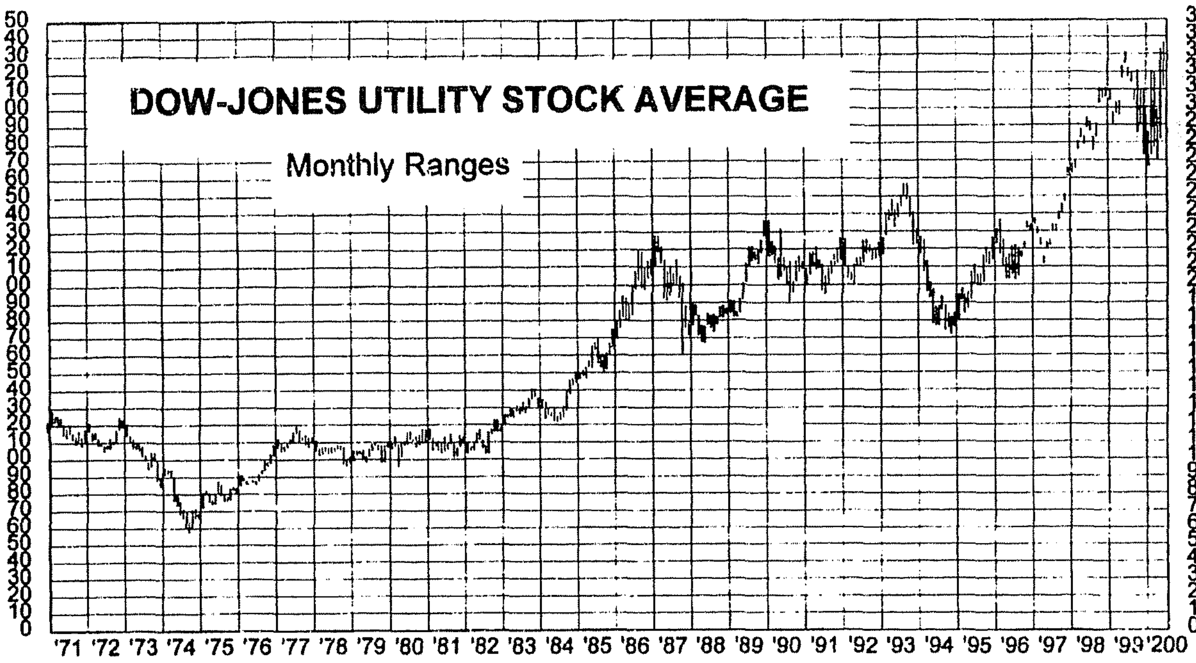
NATURAL GAS COMMON STOCK AVERAGES

(Average prices and yields are based on prices for last Friday of each month.
Weekly averages, as of Friday, are published regularly in Moody's "News Reports.")

TRANSMISSION STOCKS

MARKET PRICE - WEIGHTED AVERAGE - $ PER SHARE

Year	Aver.	Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep	Oct.	Nov.	Dec.
2001	......	1233.84	854.55	762.53	844.85	738.48	649.86	......	......	......	......	......	......
2000	1118.32	903.75	901.96	1042.28	1002.40	1017.68	1007.09	1100.33	1248.94	1316.39	1316.52	1258.26	1304.21
1999	796.45	727.33	739.64	764.82	839.69	885.71	872.75	869.41	866.93	789.50	771.97	699.68	729.91
1998	667.59	606.71	663.45	668.01	679.27	685.47	687.47	672.68	596.54	671.29	675.55	707.95	696.74
1997	547.00	503.06	481.40	497.70	521.82	559.32	550.84	556.79	562.82	581.98	570.29	580.22	597.79
1996	463.66	402.28	427.48	424.60	458.28	451.17	460.91	443.00	445.90	456.90	507.85	542.53	543.00
1995	358.40	310.04	333.96	340.92	359.70	358.75	354.48	359.71	356.47	368.18	367.07	384.33	407.21
1994	325.61	347.01	334.57	333.36	315.70	316.01	321.83	341.96	329.92	323.25	338.96	299.85	304.94
1993	319.19	256.06	285.44	305.46	296.00	299.39	321.64	332.06	370.69	352.85	350.14	341.29	319.21
1992	232.92	203.36	210.03	202.19	215.85	234.17	219.54	248.80	254.22	254.39	261.76	244.78	245.99
1991	218.48	183.72	201.66	200.97	226.32	240.06	212.67	228.36	233.19	228.42	230.51	220.79	215.11
1990	217.50	208.03	227.79	227.22	219.40	230.60	227.47	219.63	206.54	217.84	216.44	211.57	197.48
1989	214.84	195.71	193.29	185.60	198.50	205.87	210.36	226.86	231.06	231.20	223.11	229.88	246.50
1988	169.47	152.75	161.45	161.79	165.57	164.29	174.63	171.99	172.73	175.13	181.60	173.67	178.01
1987	182.72	173.76	181.68	194.80	189.12	190.67	195.62	206.0	209.34	204.64	151.28	151.24	144.47
1986	164.64	172.17	167.26	167.87	160.59	170.39	174.88	153.50	170.95	168.43	154.26	159.33	156.08
1985	166.62	151.88	156.40	175.69	175.13	172.12	167.48	161.84	165.39	157.20	167.94	172.47	175.87
1984	143.76	148.49	141.37	148.78	151.60	143.76	137.19	133.09	145.07	147.84	141.12	141.42	145.38
1983	132.43	114.09	114.50	111.63	118.70	128.44	147.29	140.18	142.60	146.40	144.83	137.48	142.96
1982	109.14	123.81	112.84	111.10	111.57	107.32	99.17	90.74	102.18	109.67	116.53	110.41	114.32
1981	142.49	164.39	156.54	158.46	144.53	140.53	137.87	145.98	141.12	125.65	128.46	130.94	135.42
1980	147.77	139.41	145.09	118.65	120.85	130.55	138.88	145.05	142.06	154.84	155.94	198.32	183.65
1979	111.37	93.35	91.62	99.06	102.29	102.13	109.73	114.16	122.71	123.54	113.72	130.02	134.10
1978	91.81	87.97	89.07	90.93	96.68	97.93	94.09	93.91	93.71	93.96	87.61	88.79	87.09
1977	99.50	104.72	99.22	97.77	99.07	99.47	106.63	102.08	94.05	99.26	93.48	100.57	97.73
1976	90.66	83.67	82.32	83.42	83.17	86.31	94.77	95.06	90.63	95.89	92.00	95.64	105.00
1975	71.34	67.30	67.21	67.72	66.47	69.13	77.46	76.52	73.12	73.01	72.43	72.88	72.85
1974	63.40	78.80	74.98	74.23	66.81	61.49	58.86	61.06	51.93	51.71	57.08	60.98	62.81
1973	78.16	90.65	87.82	83.13	80.16	78.75	72.13	72.91	66.89	77.04	83.20	69.72	75.55
1972	82.03	79.63	75.91	77.41	77.17	77.58	76.31	77.38	84.01	84.56	88.84	90.86	94.65
1971	80.81	84.16	82.79	85.75	89.72	83.61	80.31	82.63	80.37	76.33	73.66	71.63	78.78
1970	72.31	68.31	72.12	73.32	70.38	64.01	65.79	69.19	74.39	74.48	77.17	75.58	82.95
1969	78.27	90.86	87.31	83.18	83.03	84.45	76.24	71.96	73.18	69.65	75.24	73.93	70.19
1968	83.34	80.77	77.59	74.44	78.49	80.49	85.21	84.16	83.72	85.24	85.80	91.17	93.03
1967	74.21	67.55	68.06	70.46	72.33	72.01	72.33	74.81	77.43	81.88	78.96	76.61	78.11
1966	68.42	75.35	73.26	72.63	72.09	70.38	68.42	67.45	62.52	60.96	65.46	66.42	66.08
1965	76.58	78.96	79.85	79.33	78.31	77.12	73.28	73.77	73.89	75.26	77.95	75.78	75.50
1964	69.68	66.55	64.88	65.65	67.64	67.31	68.16	70.68	70.81	69.49	71.23	76.49	77.27
1963	65.67	63.56	64.25	64.67	67.91	67.66	66.91	64.87	66.59	65.84	65.36	64.56	65.81
1962	61.04	65.00	67.18	67.76	67.02	62.15	56.22	59.43	61.05	58.41	52.61	57.29	58.33
1961	64.28	63.43	65.42	65.41	65.38	64.99	61.27	62.61	63.51	60.12	64.11	69.14	65.91
1960	57.90	56.51	55.51	57.66	68.06	56.84	56.37	56.79	59.31	56.82	57.50	60.54	62.83
1959	59.06	65.41	65.41	63.22	60.00	58.66	55.68	59.39	59.45	54.24	54.61	54.82	57.80
1958	54.69	48.85	47.74	48.24	52.05	53.50	54.86	54.87	56.63	57.57	59.23	58.71	64.05
1957	52.00	54.79	52.90	54.60	57.93	57.79	56.65	55.57	50.51	49.01	45.70	46.17	42.39
1956	47.90	46.47	45.87	46.32	46.12	46.51	47.24	51.21	49.67	47.34	48.33	48.68	51.08
1955	45.25	41.48	43.31	44.34	45.05	45.12	44.71	45.15	46.32	45.58	45.86	48.77	47.20
1954	37.41	35.03	34.84	35.10	36.19	37.89	37.48	37.64	38.58	38.90	37.65	39.13	40.54



DIVIDEND RATE - WEIGHTED AVERAGE - $ PER SHARE

Year	Aver	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2001		10.95	10.95	10.95	10.95	10.95	10.95						
2000	10.95	10.95	10.95	10.95	10.95	10.95	10.95	10.95	10.95	10.95	10.95	10.95	10.95
1999	10.95	10.95	10.95	10.95	10.95	10.95	10.95	10.95	10.95	10.95	10.95	10.95	10.95
1998	10.78	10.54	10.74	10.74	10.74	10.74	10.74	10.74	10.74	10.74	10.95	10.95	10.95
1997	10.20	10.13	10.13	10.13	10.13	10.13	10.13	10.13	10.13	10.13	10.13	10.54	10.54
1996	9.63	9.45	9.45	9.45	9.45	9.45	9.45	9.59	9.59	9.59	9.80	10.13	10.13
1995	8.84	8.68	8.68	8.68	8.82	8.82	8.82	8.82	8.82	8.82	9.03	9.03	9.03
1994	8.11	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.26	8.26	8.26
1993	7.36	7.11	7.11	7.11	7.11	7.11	7.11	7.24	7.52	7.52	7.74	7.83	7.83
1992	6.97	6.92	6.92	6.92	6.92	6.92	6.92	6.92	6.92	6.92	7.11	7.11	7.11
1991	7.11	7.16	7.16	7.16	7.16	7.16	7.16	7.16	7.16	7.16	7.27	6.82	6.82
1990	7.91	8.66	8.66	8.66	8.66	8.66	8.66	7.16	7.16	7.16	7.16	7.16	7.16
1989	8.86	8.86	8.86	8.86	8.86	8.86	8.86	8.86	8.86	8.86	8.86	8.86	8.86
1988	8.86	8.86	8.86	8.86	8.86	8.86	8.86	8.86	8.86	8.86	8.86	8.86	8.86
1987	9.05	9.23	9.23	9.23	9.23	9.29	9.29	8.86	8.86	8.86	8.86	8.86	8.86
1986	9.67	9.93	9.93	9.93	9.93	9.93	9.93	10.06	9.35	9.35	9.23	9.23	9.23
1985	9.62	9.42	9.42	9.42	9.42	9.46	9.66	9.72	9.72	9.72	9.72	9.88	9.91
1984	9.11	8.92	8.92	8.92	8.92	8.96	9.04	9.21	9.21	9.21	9.21	9.36	9.39
1983	8.83	8.93	8.97	8.97	8.97	8.59	8.59	8.77	8.77	8.77	8.87	8.87	8.89
1982	8.67	8.45	8.56	8.56	8.56	8.56	8.56	8.64	8.75	8.75	8.90	8.90	8.90
1981	8.05	7.69	7.85	7.85	7.85	7.85	7.85	8.23	8.23	8.29	8.29	8.29	8.29
1980	7.36	7.00	7.15	7.20	7.20	7.20	7.20	7.47	7.55	7.59	7.59	7.59	7.59
1979	6.59	6.25	6.31	6.34	6.34	6.40	6.40	6.67	6.70	6.70	6.92	7.00	7.00
1978	5.87	5.64	5.71	5.71	5.71	5.74	5.74	5.84	5.81	5.89	6.14	6.25	6.25
1977	5.42	5.12	5.17	5.20	5.24	5.28	5.28	5.61	5.61	5.64	5.64	5.64	5.64
1976	4.99	4.78	4.86	4.86	4.91	4.93	4.93	5.06	5.06	5.12	5.12	5.12	5.12
1975	4.65	4.49	4.53	4.53	4.53	4.56	4.56	4.75	4.75	4.75	4.75	4.78	4.78
1974	4.42	4.26	4.26	4.26	4.31	4.32	4.32	4.56	4.56	4.56	4.56	4.59	4.49
1973	4.17	4.13	4.13	4.13	4.13	4.14	4.14	4.14	4.14	4.14	4.24	4.26	4.26
1972	4.06	4.02	4.02	4.02	4.02	4.03	4.03	4.05	4.08	4.08	4.11	4.13	4.13
1971	3.93	3.91	3.91	3.91	3.91	3.91	3.91	3.91	3.91	3.91	3.91	4.02	4.02
1970	3.81	3.77	3.77	3.81	3.81	3.81	3.81	3.87	3.87	3.87	3.91	3.91	3.91
1969	3.76	3.75	3.75	3.75	3.75	3.75	3.75	3.75	3.75	3.75	3.77	3.77	3.77
1968	3.65	3.61	3.62	3.62	3.62	3.62	3.62	3.62	3.65	3.65	3.65	3.75	3.75
1967	3.49	3.42	3.43	3.43	3.43	3.43	3.44	3.50	3.51	3.51	3.58	3.61	3.61
1966	3.34	3.28	3.30	3.30	3.31	3.31	3.31	3.35	3.35	3.35	3.38	3.42	3.42
1965	3.10	3.01	3.01	3.01	3.03	3.06	3.06	3.06	3.07	3.07	3.25	3.28	3.28
1964	2.89	2.85	2.88	2.88	2.88	2.88	2.88	2.88	2.91	2.91	2.91	2.93	2.93
1963	2.77	2.73	2.73	2.73	2.73	2.76	2.76	2.76	2.79	2.79	2.79	2.82	2.82
1962	2.73	2.83	2.83	2.83	2.83	2.85	2.85	2.85	2.87	2.87	2.39	2.39	2.39
1961	2.83	2.81	2.81	2.81	2.81	2.85	2.85	2.85	2.87	2.83	2.83	2.83	2.83
1960	2.67	2.54	2.54	2.54	2.51	2.68	2.68	2.69	2.69	2.69	2.80	2.81	2.81
1959	2.45	2.43	2.44	2.44	2.44	2.44	2.44	2.44	2.44	2.44	2.45	2.49	2.54
1958	2.41	2.31	2.41	2.41	2.42	2.42	2.42	2.42	2.42	2.42	2.43	2.43	2.43
1957	2.28	2.23	2.28	2.28	2.28	2.29	2.29	2.29	2.29	2.29	2.29	2.29	2.31
1956	2.09	2.05	2.05	2.05	2.05	2.05	2.05	2.05	2.09	2.11	2.12	2.22	2.23
1955	1.83	1.80	1.80	1.80	1.84	1.84	1.86	1.86	1.86	1.86	2.00	2.00	2.01
1954	1.75	1.68	1.69	1.69	1.71	1.73	1.73	1.79	1.80	1.80	1.80	1.80	1.80

YIELD - %

Year	Aver.	Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
2001	......	0.89	1.28	1.44	1.30	1.48	1.68	......	......	......	......	......	......
2000	1.07	1.21	1.21	1.05	1.09	1.08	1.09	1.00	0.88	0.83	0.83	0.87	0.84
1999	1.38	1.51	1.48	1.43	1.30	1.24	1.25	1.26	1.26	1.39	1.42	1.56	1.50
1998	1.62	1.74	1.62	1.61	1.58	1.57	1.56	1.60	1.80	1.60	1.62	1.52	1.57
1997	1.87	2.01	2.10	2.04	1.94	1.81	1.84	1.82	1.80	1.74	1.78	1.82	1.76
1996	2.09	2.35	2.21	2.23	2.06	2.09	2.05	2.16	2.15	2.10	1.93	1.87	1.87
1995	2.48	2.80	2.60	2.55	2.45	2.46	2.49	2.45	2.47	2.40	2.46	2.35	2.22
1994	2.50	2.32	2.41	2.42	2.55	2.56	2.50	2.36	2.44	2.49	2.44	2.75	2.71
1993	2.32	2.78	2.49	2.33	2.40	2.37	2.21	2.18	2.03	2.13	2.21	2.29	2.45
1992	2.99	3.40	3.29	3.42	3.21	2.96	3.15	2.78	2.72	2.72	2.72	2.90	2.89
1991	3.36	3.90	3.55	3.56	3.16	2.98	3.37	4.14	3.07	3.13	3.15	3.09	3.17
1990	3.64	4.16	3.80	3.81	3.95	3.76	3.81	3.26	3.47	3.29	3.31	3.38	3.63
1989	4.12	4.53	4.58	4.77	4.46	4.30	4.21	3.91	3.83	3.83	3.97	3.86	3.59
1988	5.23	5.80	5.49	5.48	5.35	5.39	5.07	5.15	5.13	5.06	4.88	5.10	4.98
1987	4.95	5.31	5.08	4.74	4.88	4.87	4.75	4.30	4.23	4.33	5.86	5.86	6.13
1986	5.87	5.77	5.94	5.92	6.18	5.83	5.68	6.55	5.47	5.55	5.98	5.79	5.91
1985	5.77	6.20	6.02	5.36	5.38	5.50	5.77	6.01	5.88	6.18	5.79	5.73	5.63
1984	6.34	6.01	6.31	6.00	5.88	6.23	6.59	6.92	6.35	6.23	6.53	6.62	6.46
1983	6.75	7.83	7.83	8.04	7.56	6.69	5.83	6.26	6.15	5.99	6.12	6.45	6.22
1982	7.94	6.83	7.59	7.70	7.67	7.98	8.63	9.52	8.56	7.98	7.64	8.06	7.79
1981	5.65	4.68	5.01	4.95	5.43	5.59	5.69	5.64	5.83	6.60	6.45	6.33	6.12
1980	4.98	5.02	4.93	6.07	5.96	5.52	5.18	5.15	5.31	4.90	4.87	3.83	4.13
1979	5.98	6.70	6.89	6.40	6.20	6.27	5.83	5.84	5.46	5.42	6.09	5.38	5.22
1978	6.41	6.41	6.41	6.28	5.91	5.86	6.10	6.22	6.23	6.27	7.01	7.04	7.18
1977	5.45	4.89	5.21	5.32	5.29	5.31	4.95	5.50	5.96	5.68	6.03	5.61	5.77
1976	5.52	5.71	5.90	5.83	5.90	5.71	5.20	5.32	5.58	5.34	5.57	5.35	4.88
1975	6.53	6.67	6.74	6.69	6.82	6.60	5.89	6.21	6.50	6.51	6.56	6.56	6.56
1974	6.97	5.41	5.68	5.74	6.45	7.03	7.34	7.47	8.78	8.82	7.85	7.53	7.15
1973	5.34	4.56	4.70	4.97	5.15	5.26	5.74	5.68	6.19	5.37	5.10	6.11	5.64
1972	4.94	5.05	5.30	5.19	5.21	5.19	5.28	5.23	4.86	4.82	4.63	4.55	4.36
1971	4.86	4.65	4.72	4.56	4.36	4.68	4.87	4.73	4.87	5.12	5.31	5.61	5.10
1970	5.31	5.52	5.23	5.20	5.41	5.95	5.79	5.59	5.20	5.20	5.07	5.17	4.71
1969	4.80	4.13	4.30	4.51	4.52	4.44	4.92	5.21	5.12	5.38	5.01	5.10	5.37
1968	4.39	4.47	4.67	4.86	4.61	4.50	4.25	4.30	4.36	4.28	4.25	4.11	4.03
1967	4.70	5.06	5.04	4.87	4.74	4.78	4.76	4.68	4.53	4.29	4.53	4.71	4.62
1966	4.88	4.35	4.50	4.54	4.59	4.70	4.84	4.97	5.36	5.50	5.16	5.15	5.18
1965	4.05	3.81	3.77	3.79	3.87	3.97	4.18	4.15	4.15	4.08	4.17	4.33	4.34
1964	4.14	4.28	4.44	4.39	4.26	4.28	4.23	4.07	4.11	4.19	4.09	3.83	3.79
1963	4.22	4.30	4.25	4.22	4.02	4.08	4.12	4.25	4.19	4.24	4.27	4.37	4.29
1962	4.47	4.35	4.21	4.18	4.22	4.59	5.07	4.80	4.70	4.91	4.54	4.17	4.10
1961	4.40	4.43	4.30	4.30	4.30	4.39	4.65	4.55	4.52	4.71	4.41	4.09	4.29
1960	4.61	4.49	4.58	4.41	4.37	4.71	4.75	4.75	4.54	4.73	4.87	4.64	4.47
1959	4.17	3.72	3.73	3.86	4.07	4.16	4.38	4.11	4.10	4.50	4.49	4.54	4.39
1958	4.44	4.73	5.05	5.00	4.65	4.52	4.41	4.41	4.27	4.20	4.10	4.14	3.79
1957	4.44	4.07	4.31	4.18	3.94	3.96	4.04	4.12	4.53	4.67	5.01	4.96	5.45
1956	4.37	4.41	4.47	4.43	4.44	4.41	4.34	4.00	4.21	4.46	4.39	4.56	4.37
1955	4.15	4.34	4.16	4.06	4.08	4.07	4.16	4.12	4.02	4.08	4.36	4.10	4.26
1954	4.68	4.80	4.85	4.81	4.73	4.57	4.62	4.76	4.66	4.63	4.78	4.60	4.40

DISTRIBUTION STOCKS

MARKET PRICE - WEIGHTED AVERAGE - $ PER SHARE

Year	Aver	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec.
2001		207.25	210.48	200.51	214.32	217.25	208.20	......	......	......	......	......	......
2000	179.68	159.52	145.71	175.18	168.65	167.63	170.45	174.81	184.25	205.84	194.63	208.79	200.68
1999	165.47	162.28	149.41	142.14	149.57	154.79	156.91	159.60	193.67	183.42	187.58	179.48	166.84
1998	176.77	181.25	184.14	186.15	180.81	181.36	176.31	165.36	163.82	173.49	174.74	176.55	177.24
1997	167.34	162.04	159.63	158.88	153.52	159.88	165.98	168.44	168.35	174.44	168.51	177.39	191.04
1996	157.86	156.67	156.06	153.32	151.19	152.37	159.35	150.89	163.83	152.81	161.73	169.50	166.64
1995	139.25	129.40	133.19	134.60	136.95	133.05	137.29	134.92	138.50	141.93	143.65	151.62	155.94
1994	137.40	153.94	147.37	145.48	143.10	137.30	133.75	136.04	134.07	131.60	134.72	124.42	126.96
1993	153.25	141.38	149.95	154.64	149.52	150.29	154.88	160.66	159.91	157.08	156.75	149.91	154.06
1992	130.84	124.82	122.94	118.83	118.84	125.13	129.16	137.53	139.53	141.72	136.99	135.85	138.79
1991	115.93	106.89	108.26	110.12	112.07	114.84	111.10	116.21	117.21	121.79	123.56	124.76	124.32
1990	106.48	103.70	108.55	107.51	104.14	106.18	107.14	102.86	100.83	105.58	108.00	109.37	108.86
1989	100.74	88.46	87.23	90.65	95.47	96.64	99.91	104.05	104.80	106.50	106.30	111.83	117.05
1988	86.60	84.16	86.75	83.68	84.75	85.84	89.64	89.39	[illegible]	88.10	87.12	88.58	86.76
1987	87.45	95.68	96.29	96.20	88.15	84.64	90.26	87.29	90.47	86.21	78.23	78.73	77.25
1986	90.34	77.93	81.41	86.99	90.63	91.53	94.35	94.20	98.11	91.99	92.69	93.36	90.89
1985	76.00	71.68	72.00	75.57	75.49	78.96	81.61	77.49	75.70	74.09	74.52	78.28	76.58
1984	60.61	58.41	55.95	56.59	58.23	57.86	56.87	56.63	62.27	62.50	65.65	66.62	69.70
1983	54.81	52.38	51.49	51.07	51.58	54.37	56.96	56.06	56.05	57.48	57.53	57.04	55.79
1982	49.66	51.28	49.09	49.16	49.46	48.64	48.27	46.06	50.51	50.26	51.85	50.67	50.62
1981	54.62	54.67	59.73	58.06	55.78	54.47	54.79	54.13	55.28	49.61	50.35	55.06	53.50
1980	52.79	54.59	51.57	44.45	49.52	51.12	54.05	53.97	49.87	53.02	55.76	58.91	56.61
1979	52.15	49.05	49.11	49.82	49.68	50.06	54.04	54.95	58.56	54.74	49.31	52.94	53.50
1978	49.04	50.45	50.44	50.08	49.71	48.23	48.46	48.86	51.01	50.12	47.59	47.57	45.97
1977	51.18	52.74	49.22	49.30	49.86	50.56	53.71	53.31	51.90	51.66	50.08	50.99	50.88
1976	45.53	42.57	42.79	43.40	43.60	44.08	43.98	45.60	46.36	47.97	47.04	47.12	51.80
1975	38.98	36.48	38.05	36.78	37.89	40.35	43.25	41.04	38.32	38.65	39.07	39.60	38.29
1974	35.78	44.30	43.43	43.59	39.84	35.82	33.70	33.89	29.49	30.70	32.67	32.17	29.71
1973	47.65	48.88	48.69	49.40	49.01	48.91	48.13	47.44	46.96	48.88	49.09	43.00	43.43
1972	46.73	49.54	47.30	46.71	45.16	44.58	44.05	44.60	44.29	43.86	46.68	50.39	53.54
1971	49.30	[illegible]	52.96	52.33	50.80	49.79	48.10	48.21	47.98	47.55	46.31	[illegible]	47.86
1970	46.48	[illegible]	46.05	48.28	46.68	43.80	43.50	43.89	45.81	46.80	46.89	49.37	52.33
1969	49.26	54.53	52.32	51.52	51.82	52.20	49.36	47.96	47.39	46.50	48.00	45.68	43.88
1968	52.10	53.87	51.92	49.19	49.86	49.50	52.77	52.92	51.32	52.29	52.31	55.49	53.80
1967	52.68	55.62	54.31	55.49	54.48	52.43	51.85	51.88	51.92	52.72	51.06	41.95	50.49
1966	59.64	63.97	59.98	61.09	58.34	57.04	56.64	54.39	51.50	51.50	53.40	51.03	53.50
1965	67.77	71.82	71.83	69.73	69.46	67.46	66.64	66.27	66.30	67.23	66.76	65.48	64.31
1964	67.75	65.27	66.22	67.25	67.12	66.82	66.56	68.85	68.82	69.39	69.39	69.07	68.24
1963	65.65	62.80	63.91	63.86	66.50	67.59	66.23	66.17	[illegible]	66.94	67.33	65.14	64.62
1962	59.78	63.35	64.11	65.64	65.10	59.23	53.38	59.04	58.25	56.47	54.14	58.89	59.73
1961	59.36	49.13	52.01	55.21	59.42	59.56	56.40	59.32	61.83	63.71	63.43	67.28	64.96
1960	42.89	38.84	38.53	40.51	40.80	41.36	42.16	43.92	46.25	43.88	44.07	46.09	48.21
1959	39.88	39.66	39.45	39.42	39.66	40.67	38.98	40.21	41.60	39.47	39.88	40.02	39.59
1958	33.20	28.29	29.10	30.22	31.67	32.53	33.50	33.93	34.02	34.89	35.51	35.93	38.71
1957	27.49	28.93	28.79	28.76	28.24	28.53	27.86	28.05	27.20	26.67	25.53	25.50	25.78
1956	28.41	[illegible]	28.34	28.31	27.91	27.68	28.07	28.74	29.18	28.75	28.85	28.42	28.23
1955	27.98	27.13	27.75	27.43	27.89	27.61	28.15	28.20	28.46	28.56	28.00	28.42	28.10
1954	24.03	22.43	22.59	22.19	23.22	23.24	23.68	24.85	25.04	25.00	24.55	24.93	26.47

DIVIDEND RATE - WEIGHTED AVERAGE - $ PER SHARE

Year	Aver.	Jan	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
2001	. . .	8.22	8.22	8.22	8.22	8.22	8.22	. . .	. . .	. . .	. . .	. . .	. . .
2000	8.22	8.22	8.22	8.22	8.22	8.22	8.22	8.22	8.22	8.22	8.22	8.22	8.22
1999	8.18	8.13	8.16	8.16	8.16	8.16	8.16	8.16	8.22	8.22	8.22	8.22	8.22
1998	8.12	8.02	8.07	8.13	8.13	8.13	8.13	8.13	8.13	8.13	8.13	8.13	8.13
1997	7.99	7.91	7.94	7.94	7.98	8.00	8.00	8.02	8.02	8.02	8.02	8.02	8.02
1996	8.01	7.56	7.59	7.61	7.61	8.83	8.83	8.83	7.83	7.83	7.83	7.87	7.91
1995	7.48	7.44	7.44	7.45	7.46	7.46	7.46	7.46	7.49	7.49	7.50	7.52	7.56
1994	7.36	7.30	7.32	7.32	7.36	7.36	7.36	7.38	7.38	7.38	7.38	7.39	7.44
1993	7.23	7.14	7.17	7.17	7.22	7.22	7.22	7.26	7.26	7.26	7.27	7.27	7.30
1992	7.08	6.99	7.02	7.05	7.05	7.08	7.08	7.11	7.11	7.11	7.11	7.11	7.14
1991	6.94	6.84	6.90	6.94	6.94	6.94	6.94	6.94	6.94	6.94	6.96	6.96	6.99
1990	6.70	6.58	6.63	6.68	6.68	6.68	6.68	6.68	6.72	6.72	6.73	6.80	6.84
1989	6.45	6.30	6.38	6.43	6.43	6.43	6.43	6.44	6.47	6.47	6.48	6.54	6.58
1988	6.15	6.02	6.09	6.09	6.13	6.13	6.13	6.15	6.16	6.16	6.18	6.26	6.30
1987	5.86	5.71	5.82	5.82	5.84	5.84	5.84	5.86	5.86	5.86	5.86	5.98	6.02
1986	5.68	6.22	6.31	5.51	5.51	5.51	5.51	5.52	5.54	5.54	5.55	5.69	5.71
1985	[illegible]	5.88	5.99	6.01	6.03	6.03	6.03	6.05	6.07	6.07	6.09	6.19	6.22
1984	5.71	5.55	5.63	5.66	5.66	5.66	5.67	5.70	5.73	5.73	5.75	5.85	5.88
1983	5.45	5.39	5.39	5.45	5.40	5.42	5.42	5.44	5.46	5.46	5.48	5.53	5.55
1982	5.28	5.12	5.15	5.27	5.29	5.29	5.29	5.31	5.31	5.31	5.31	5.34	5.39
1981	4.95	4.76	4.76	4.90	4.96	4.96	4.96	4.98	4.98	4.98	4.98	5.04	5.12
1980	4.59	4.44	4.45	4.58	4.61	4.61	4.61	4.62	4.62	4.62	4.62	4.62	4.68
1979	4.33	4.18	4.18	4.32	4.34	4.34	4.34	4.36	4.36	4.36	4.36	4.38	4.44
1978	4.07	3.93	3.93	4.01	4.06	4.07	4.07	4.11	4.11	4.11	4.12	4.15	4.18
1977	3.85	3.70	3.71	3.84	3.87	3.87	3.87	3.87	3.88	3.88	3.88	3.90	3.93
1976	3.65	3.48	3.55	3.62	3.62	3.69	3.69	3.70	3.70	3.70	3.70	3.70	3.70
1975	3.43	3.34	3.34	3.39	3.40	3.41	3.41	3.42	3.48	3.48	3.48	3.48	3.48
1974	3.31	3.29	3.29	3.29	3.29	3.30	3.30	3.30	3.30	3.30	3.34	3.34	3.34
1973	3.21	3.12	3.13	3.18	3.18	3.19	3.19	3.22	3.23	3.23	3.23	3.28	3.28
1972	3.10	3.07	3.08	3.10	3.10	3.10	3.10	3.11	3.11	3.11	3.11	3.12	3.12
1971	3.06	3.02	3.02	3.06	3.06	3.06	3.06	3.07	3.07	3.07	3.07	3.07	3.07
1970	2.97	2.93	2.93	2.97	2.97	2.97	2.97	2.98	2.98	2.98	2.98	3.01	3.01
1969	2.88	2.81	2.81	2.87	2.87	2.88	2.88	2.89	2.90	2.90	2.90	2.93	2.93
1968	2.79	2.74	2.74	2.78	2.78	2.79	2.79	2.80	2.80	2.80	2.80	2.80	2.81
1967	[illegible]	2.61	2.61	2.65	2.65	2.66	2.67	2.68	2.68	2.71	2.71	2.71	2.74
1966	2.75	2.48	2.48	2.55	2.55	2.56	2.56	2.57	2.57	2.58	2.58	2.58	2.61
1965	2.40	2.31	2.33	2.37	2.39	2.39	2.39	2.41	2.41	2.41	2.41	2.45	2.48
1964	2.27	2.19	2.19	2.25	2.25	2.28	2.28	2.28	2.28	2.30	2.30	2.30	2.30
1963	2.13	2.02	2.02	2.09	2.10	2.14	2.16	2.16	2.16	2.16	2.16	2.18	2.18
1962	2.01	1.97	1.97	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.02	2.02
1961	1.91	1.84	1.84	1.91	1.91	1.92	1.92	1.92	1.92	1.92	1.92	1.94	1.94
1960	1.79	1.69	1.70	1.77	1.80	1.80	1.80	1.81	1.81	1.81	1.81	1.84	1.84
1959	1.63	1.57	1.57	1.62	1.62	1.64	1.64	1.64	1.64	1.65	1.66	1.66	1.66
1958	1.53	1.49	1.49	1.51	1.51	1.52	1.52	1.54	1.55	1.56	1.56	1.57	1.57
1957	1.49	1.49	1.49	1.49	1.49	1.49	1.49	1.49	1.49	1.49	1.49	1.49	1.49
1956	1.43	1.39	1.39	1.39	1.39	1.40	1.44	1.44	1.44	1.46	1.46	1.47	1.48
1955	1.32	1.25	1.25	1.28	1.28	1.28	1.28	1.32	1.37	1.37	1.37	1.38	1.38
1954	1.19	1.16	1.16	1.16	1.16	1.17	1.21	1.21	1.21	1.21	1.21	1.21	1.25

YIELD - %

Year	Aver	Jan	Feb	Mar	Apr.	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec.
2001		3.97	3.91	4.10	3.84	3.78	3.95			. . .	. . .	. . .	. . .
2000	4.62	5.15	5.64	4.69	4.87	[illegible]	4.82	4.70	4.46	3.99	4.22	3.94	4.10
1999	4.99	5.01	5.46	5.74	5.46	5.27	5.20	5.11	4.24	4.47	4.38	4.58	4.93
1998	4.60	4.42	4.38	4.37	4.50	4.48	4.61	4.96	4.96	4.69	4.65	4.61	4.59
1997	4.79	4.88	4.97	5.00	5.19	5.00	4.82	4.76	4.76	4.60	4.76	4.52	4.20
1996	5.09	4.83	4.86	4.96	5.03	5.85	5.54	5.85	4.78	5.12	4.84	4.64	4.75
1995	5.38	5.75	5.59	5.53	5.45	5.61	5.43	5.53	5.41	5.28	5.22	4.96	4.85
1994	5.38	4.74	4.97	5.03	5.14	5.36	5.50	5.42	5.50	5.61	5.48	5.94	5.86
1993	4.72	5.05	4.78	4.64	4.83	4.80	4.66	4.52	4.54	4.62	4.64	4.85	4.74
1992	5.41	5.60	5.71	5.93	5.93	5.66	5.48	5.17	5.10	5.02	5.19	5.23	5.14
1991	6.00	6.40	6.37	6.30	6.19	6.04	6.25	5.97	5.92	5.70	5.63	5.58	5.62
1990	6.29	6.06	6.11	6.21	6.41	6.29	6.24	6.49	6.66	6.36	6.23	6.22	6.28
1989	6.40	7.12	7.31	7.09	6.74	6.65	6.44	6.19	6.17	6.07	6.10	5.85	5.63
1988	7.10	7.15	7.02	7.28	7.23	7.14	6.84	6.88	7.30	6.99	7.09	7.07	7.22
1987	6.70	5.97	6.04	6.05	6.63	6.90	6.47	6.71	6.48	6.80	7.49	7.60	7.79
1986	6.29	7.98	7.75	6.33	6.08	6.02	5.84	5.86	5.65	6.46	5.99	6.09	6.28
1985	7.97	8.20	8.32	7.95	7.99	7.64	7.39	7.81	8.02	8.19	8.17	7.91	8.12
1984	9.42	9.50	10.06	10.00	9.72	9.78	9.97	10.07	9.20	9.17	8.76	8.78	8.44
1983	9.96	10.29	10.47	10.67	10.47	9.97	9.52	9.70	9.74	9.50	9.53	9.69	9.95
1982	10.63	9.98	10.49	10.72	10.70	10.88	10.96	11.53	10.51	10.57	10.24	10.54	10.65
1981	9.06	8.71	7.97	8.44	8.89	9.11	9.05	9.20	9.01	10.04	9.89	9.15	9.57
1980	8.69	8.13	8.63	10.30	9.31	9.02	8.53	8.56	9.26	8.71	8.29	7.84	8.27
1979	8.30	8.52	8.51	8.67	8.74	8.67	8.03	7.93	7.45	7.96	8.84	8.27	8.30
1978	8.31	7.79	7.79	8.01	8.17	8.44	8.40	8.41	8.06	8.20	8.66	8.72	9.09
1977	7.52	7.02	7.54	7.79	7.76	7.65	7.21	7.26	7.48	7.51	7.75	7.65	7.72
1976	8.04	8.17	8.30	8.34	8.30	8.37	8.39	8.11	7.98	7.71	7.87	7.85	7.14
1975	8.81	9.16	[illegible]	9.22	8.97	8.45	7.88	8.33	9.08	9.00	8.91	8.79	9.09
1974	9.25	7.43	7.58	7.55	8.26	9.21	9.79	9.74	11.19	10.72	10.22	10.38	11.24
1973	6.74	6.38	6.43	6.44	6.49	6.52	6.63	6.79	6.88	6.61	6.58	7.63	7.55
1972	6.63	6.20	6.51	6.64	6.86	6.95	7.04	6.97	7.02	7.09	6.66	6.19	5.83
1971	6.21	5.59	5.70	5.85	6.02	6.15	6.36	6.37	6.40	6.46	6.62	6.72	6.41
1970	6.39	6.61	6.36	6.15	6.36	6.78	6.83	6.79	6.51	6.37	6.36	6.10	5.75
1969	5.85	5.15	5.37	5.57	5.54	5.53	5.83	6.03	6.12	6.24	6.04	6.41	6.68
1968	5.36	5.09	5.28	5.65	5.58	5.64	5.29	5.29	5.46	5.35	5.35	5.05	5.22
1967	5.07	4.69	4.81	4.78	4.86	5.07	5.15	5.17	5.16	5.14	5.31	5.43	5.43
1966	4.61	3.88	4.13	4.17	4.37	4.49	4.52	4.73	4.99	5.01	4.83	5.06	4.88
1965	3.54	3.22	3.24	3.40	3.44	3.54	3.59	3.61	3.63	3.58	3.61	3.71	3.86
1964	3.35	3.36	3.31	3.35	3.35	3.41	3.43	3.31	3.31	3.31	3.31	3.33	3.37
1963	3.24	3.22	3.16	3.27	3.16	3.17	3.26	3.26	3.24	3.23	3.21	3.35	3.32
1962	3.36	3.11	3.07	3.06	3.09	3.30	3.77	3.40	3.45	3.56	3.71	3.43	3.38
1961	3.22	3.75	3.54	3.46	3.21	3.22	3.40	3.24	3.11	3.01	3.03	2.88	2.99
1960	4.19	4.35	4.41	4.37	4.41	4.35	4.27	4.17	3.91	4.12	4.11	3.99	3.82
1959	4.09	3.96	3.98	4.11	4.08	4.03	4.21	[illegible]	3.94	4.18	4.16	4.15	4.19
1958	4.65	5.27	5.12	4.98	4.77	4.67	4.54	4.51	4.56	4.47	4.39	4.37	4.06
1957	5.43	5.15	5.18	5.18	5.28	5.22	5.35	5.31	5.48	5.59	5.84	5.84	5.78
1956	5.03	4.89	4.90	4.91	4.98	5.06	5.13	5.01	4.93	5.08	5.06	5.17	5.24
1955	4.71	4.60	4.50	4.67	4.59	4.64	4.55	4.68	4.81	4.80	4.89	4.86	4.91
1954	4.97	5.17	5.14	[illegible]	5.00	5.00	5.11	4.87	4.83	4.81	4.93	4.85	4.72

NATURAL GAS INDUSTRY STOCKS

(Includes the transmission and distribution stocks plus the stocks of integrated companies.)

MARKET PRICE - WEIGHTED AVERAGE - $ PER SHARE

Year	Aver.	Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct	Nov.	Dec.
2001	......	640.25	466.30	410.96	465.68	417.67	368.87	......	......	......	......	......	......
2000	571.55	499.28	462.05	536.25	516.96	525.00	520.35	564.15	636.47	665.48	630.31	652.95	649.30
1999	414.94	353.03	363.13	368.64	404.33	424.21	421.01	421.14	491.67	452.99	446.73	411.46	420.88
1998	344.93	331.10	354.43	358.82	360.23	361.18	357.17	334.68	301.27	337.96	340.25	354.02	348.09
1997	305.99	285.66	273.99	278.52	312.31	301.12	301.19	306.20	312.22	320.87	321.74	323.67	334.38
1996	236.53	230.64	239.51	238.14	253.92	252.50	261.41	252.02	262.41	263.84	282.80	301.19	300.81
1995	207.15	187.02	193.41	198.26	207.32	204.97	203.85	205.24	204.99	212.89	210.33	223.05	234.44
1994	193.11	209.15	199.10	201.33	192.52	188.65	190.41	198.87	195.19	190.65	195.21	176.76	179.53
1993	202.85	172.00	186.60	197.86	194.82	195.56	205.61	210.31	227.18	219.35	215.26	209.43	200.24
1992	158.06	143.66	140.77	138.41	143.27	154.91	154.00	169.97	171.85	171.90	173.39	167.25	167.35
1991	160.17	155.67	164.57	160.10	165.52	171.23	153.09	159.42	163.16	160.76	160.95	156.19	151.38
1990	173.34	173.28	180.78	179.48	171.81	178.03	177.68	171.23	164.88	174.20	174.16	171.54	163.01
1989	170.46	152.90	152.04	149.48	158.78	165.85	169.64	180.45	170.12	185.26	179.49	184.49	197.07
1988	140.15	134.71	137.85	134.60	138.20	136.47	144.88	142.84	141.54	143.77	144.49	139.40	143.08
1987	155.58	150.28	156.46	165.21	158.74	158.85	165.83	171.44	175.73	169.71	134.02	132.09	128.63
1986	138.08	135.62	135.54	137.43	134.10	139.53	143.99	132.41	145.09	141.45	135.36	139.03	137.42
1985	132.98	121.03	125.79	137.47	134.38	138.07	135.91	131.18	131.99	126.48	136.99	137.78	138.65
1984	114.32	119.58	112.04	117.67	118.55	113.97	109.88	106.04	114.48	116.64	113.40	113.51	116.05
1983	106.76	94.71	94.27	92.24	96.65	104.96	117.07	111.80	113.05	117.22	114.48	111.29	113.40
1982	89.80	98.25	90.46	90.73	91.97	89.48	84.47	77.16	85.53	90.13	95.31	91.14	92.94
1981	111.31	124.96	119.71	119.96	111.58	109.65	108.36	114.42	112.04	100.16	102.00	105.87	106.96
1980	113.44	107.27	111.28	91.87	96.02	101.79	108.29	112.67	110.34	117.32	120.82	147.45	136.12
1979	88.25	76.14	75.45	79.96	81.48	81.31	87.10	91.13	96.30	97.44	88.67	100.24	103.72
1978	75.95	73.91	73.70	76.09	79.08	78.84	77.72	77.58	77.81	78.06	72.58	73.50	72.47
1977	80.65	82.83	78.10	77.71	79.20	80.24	85.74	83.51	77.92	81.35	78.19	82.30	80.73
1976	69.99	65.86	64.51	65.44	64.53	66.10	70.12	71.60	69.88	73.45	71.52	74.81	82.05
1975	58.21	55.97	56.78	56.71	55.61	58.34	63.04	60.79	58.14	58.26	58.37	58.39	58.15
1974	51.76	63.31	61.44	60.35	54.26	50.72	48.24	49.23	43.05	43.05	47.12	49.68	50.65
1973	64.19	71.89	70.68	67.44	66.00	64.88	60.77	60.47	56.77	63.21	65.31	63.30	59.52
1972	66.80	66.91	64.74	65.41	63.56	63.69	62.70	62.95	67.18	66.63	69.09	73.19	75.52
1971	67.01	70.71	70.01	70.93	71.16	68.34	66.11	68.09	66.64	64.00	61.68	60.59	65.90
1970	61.30	56.62	60.55	62.46	59.07	54.80	54.95	58.83	62.62	63.41	68.88	64.52	68.88
1969	63.91	73.11	70.25	68.07	67.64	68.10	62.63	60.63	60.28	58.17	61.27	59.64	57.15
1968	68.22	66.62	64.71	62.05	64.06	65.67	69.67	69.11	68.39	69.49	70.03	74.52	74.28
1967	63.69	61.83	61.55	62.57	63.60	62.52	61.88	64.27	65.60	67.81	64.70	62.54	64.90
1966	63.47	68.46	65.93	65.73	65.33	63.77	62.21	60.70	57.28	56.02	59.55	59.71	59.46
1965	70.00	72.76	72.85	72.33	71.56	70.28	67.38	68.04	68.54	69.07	69.67	68.98	68.48
1964	65.23	62.53	61.79	61.94	63.49	63.61	63.95	66.10	66.54	66.30	67.08	69.35	70.04
1963	62.47	60.76	60.72	61.01	63.24	63.89	63.26	62.43	63.80	63.36	63.07	61.87	62.28
1962	58.19	62.36	63.55	64.40	64.07	57.32	53.64	55.86	57.37	55.14	51.07	56.43	57.01
1961	59.85	55.30	57.18	58.42	60.01	59.51	57.31	58.74	60.47	60.00	62.46	65.54	63.31
1960	48.92	46.76	46.44	47.30	47.90	47.22	48.05	48.35	51.24	48.82	49.13	51.64	54.15
1959	49.26	52.43	53.05	52.86	50.20	49.21	47.14	49.37	50.11	45.95	46.58	46.38	47.75
1958	43.98	38.62	38.61	39.48	42.19	43.17	44.15	44.47	45.20	45.96	47.34	47.69	50.87
1957	39.58	41.71	40.73	41.47	42.94	43.21	41.63	41.31	38.41	37.26	35.16	36.40	34.72
1956	38.01	36.93	36.92	37.36	36.90	36.67	37.49	39.88	39.34	37.72	38.64	38.68	39.61
1955	36.37	34.69	35.72	36.04	36.48	36.27	35.13	36.51	37.14	36.49	36.17	37.70	37.10
1954	31.52	29.17	29.21	29.55	30.64	31.63	31.37	31.80	32.68	33.04	31.85	33.03	34.30

DIVIDEND RATE - WEIGHTED AVERAGE - $ PER SHARE

Year	Aver.	Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
2001		7.72	7.72	7.72	7.72	7.72	7.81		...	...	...	...	...
2000	7.72	7.72	7.72	7.72	7.72	7.72	7.72	7.72	7.72	7.72	7.72	7.72	7.72
1999	7.70	7.67	7.68	7.68	7.68	7.68	7.68	7.68	7.72	7.72	7.72	7.72	7.72
1998	7.42	7.03	7.12	7.13	7.13	7.17	7.60	7.60	7.60	7.60	7.67	7.67	7.67
1997	6.87	6.80	6.81	6.81	6.85	6.85	6.85	6.85	6.87	6.87	6.87	7.02	7.02
1996	6.66	6.49	6.50	6.50	6.55	6.81	6.82	6.82	6.59	6.59	6.65	6.78	6.79
1995	6.24	6.14	6.14	6.15	6.23	6.23	6.24	6.24	6.26	6.26	6.34	6.34	6.35
1994	5.93	5.86	5.86	5.86	5.90	5.91	5.92	5.93	5.93	5.93	6.00	6.00	6.01
1993	5.42	5.16	4.94	4.94	4.95	5.48	5.49	5.54	5.64	5.65	5.72	5.76	5.78
1992	5.33	6.38	5.61	5.62	5.62	5.05	5.06	5.06	5.07	5.07	5.13	5.13	5.15
1991	6.68	7.08	7.09	7.10	7.10	7.11	6.40	6.40	6.41	6.41	6.45	6.30	6.32
1990	7.19	7.38	7.39	7.40	7.40	7.40	7.41	6.97	6.98	6.98	6.99	7.00	7.03
1989	7.32	7.28	7.29	7.30	7.30	7.30	7.31	7.32	7.33	7.33	7.33	7.34	7.38
1988	7.22	7.51	7.52	7.35	7.12	7.12	7.12	7.13	7.13	7.13	7.13	7.15	7.19
1987	7.52	7.59	7.61	7.61	7.61	7.61	7.61	7.42	7.42	7.42	7.42	7.45	7.51
1986	7.87	8.13	8.15	8.01	8.01	8.01	8.02	8.03	7.76	7.76	7.49	7.51	7.59
1985	7.88	7.72	7.76	7.77	7.77	7.77	7.89	7.92	7.92	7.92	7.96	8.05	8.12
1984	7.49	7.33	7.34	7.37	7.38	7.40	7.44	7.53	7.54	7.54	7.58	7.67	7.71
1983	7.18	7.18	7.20	7.22	7.22	7.04	7.05	7.16	7.16	7.16	7.24	7.24	7.29
1982	7.00	7.07	7.13	6.87	6.88	6.88	6.89	6.93	7.01	7.01	7.11	7.11	7.14
1981	6.79	6.58	6.58	6.67	6.69	6.69	6.70	6.91	6.91	6.93	6.93	6.94	6.91
1980	6.24	5.99	6.07	6.11	6.17	6.17	6.18	6.31	6.34	6.36	6.38	6.40	6.45
1979	5.66	5.45	5.47	5.50	5.50	5.56	5.56	5.69	5.69	5.74	5.87	5.93	5.97
1978	5.15	4.96	4.99	5.04	5.06	5.07	5.08	5.13	5.17	5.19	5.33	5.39	5.43
1977	4.78	4.58	4.60	4.65	4.68	4.70	4.73	4.87	4.87	4.88	[illegible]	4.92	4.96
1976	4.41	4.27	4.31	4.34	4.36	4.37	4.37	4.44	4.44	4.47	4.48	4.48	4.55
1975	4.12	4.03	4.05	4.06	4.06	4.08	4.08	4.16	4.16	4.17	4.19	4.20	4.25
1974	3.91	3.80	3.81	3.82	3.84	3.87	3.87	3.97	3.97	3.97	3.98	4.00	4.01
1973	3.71	3.66	3.66	3.69	3.69	3.70	3.70	3.70	3.71	3.71	[illegible]	3.76	3.78
1972	3.59	3.55	3.55	3.56	3.57	3.58	3.58	3.59	3.60	3.60	3.61	3.63	3.65
1971	3.47	3.45	3.45	3.46	3.46	3.46	3.46	3.46	3.47	3.47	3.47	3.52	3.53
1970	3.38	3.32	3.32	3.35	3.35	3.35	3.36	3.39	3.40	3.41	3.45	3.43	3.43
1969	3.29	3.28	3.28	3.29	3.29	3.29	3.29	3.29	3.29	3.29	3.31	3.31	3.31
1968	3.22	3.17	3.18	3.19	3.22	3.22	3.22	3.22	3.23	3.23	3.23	3.25	3.26
1967	3.06	3.00	3.01	3.03	3.03	3.04	3.04	3.06	3.06	3.08	3.11	3.12	3.15
1966	2.90	2.82	2.84	2.87	2.87	2.87	2.87	2.89	2.90	2.94	2.97	2.98	2.98
1965	2.71	2.63	2.66	2.66	2.67	2.69	2.69	2.69	2.70	2.70	2.77	2.78	2.82
1964	2.54	2.49	2.50	2.52	2.52	2.53	2.53	2.53	2.56	2.56	2.56	2.56	2.57
1963	2.41	2.36	2.36	2.39	2.39	2.40	2.40	2.40	2.43	2.45	2.45	2.46	2.46
1962	2.32	2.34	2.35	2.35	2.35	2.35	2.35	2.35	2.37	2.38	2.21	2.21	2.23
1961	2.33	2.31	2.31	2.31	2.32	2.32	2.32	2.32	2.34	2.34	2.34	2.34	2.34
1960	2.19	2.10	2.11	2.12	2.13	2.18	2.18	2.19	2.20	2.20	2.27	2.27	2.30
1959	2.04	2.03	2.03	2.03	2.03	2.03	2.03	2.03	2.03	2.04	2.04	2.05	2.07
1958	1.98	1.91	1.94	1.95	1.96	1.96	1.98	1.99	1.99	1.99	2.01	2.01	2.02
1957	1.90	1.89	1.91	1.91	1.91	1.91	1.91	1.91	1.89	1.89	1.89	1.89	1.91
1956	1.77	1.74	1.74	1.74	1.74	1.74	1.74	1.74	1.76	1.78	1.82	1.86	1.88
1955	1.63	1.59	1.59	1.59	1.61	1.61	1.62	1.62	1.64	1.64	1.69	1.69	1.71
1954	1.53	1.48	1.49	1.49	1.50	1.51	1.51	1.53	1.57	1.57	1.57	1.57	1.59

YIELD - %

Year	Aver.	Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
2001	......	1.17	1.17	1.20	1.17	1.17	1.17	......	......	......	......	......	......
2000	1.37	1.55	1.67	1.44	1.49	1.47	1.48	1.37	1.21	1.16	1.22	1.17	1.17
1999	1.87	2.17	2.11	2.08	1.90	1.81	1.82	1.82	1.57	1.70	1.73	1.88	1.83
1998	2.16	2.12	2.01	1 °9	1.98	1.99	2.13	2.27	2.52	2.25	2.25	2.17	2.20
1997	2.25	2.38	2.49	2.45	2.19	2.27	2.27	2.24	2.20	2.14	2.14	2.17	2.10
1996	2.56	2.81	2.71	2.73	2.58	2.70	2.61	2.71	2.51	2.50	2.35	2.25	2.26
1995	3.02	3.28	3.17	3.10	3.01	3.04	3.06	3.04	3.05	2.94	3.01	2.84	2.71
1994	3.07	2.80	2.94	2.91	3.06	3.13	3.11	2.98	3.04	3.11	3.07	3.39	3.35
1993	2.68	3.06	2.65	2.50	2.54	2.80	2.67	2.63	2.48	2.58	2.66	2.75	2.89
1992	3.37	4.44	3.99	4.06	3.92	3.26	3.29	2.98	2.95	2.95	2.96	3.07	3.08
1991	4.17	4.55	4.31	4.43	4.29	4.15	4.18	4.01	3.93	3.99	4.01	4.03	4.17
1990	4.15	4.26	4.09	4.12	4.31	4.16	4.17	4.07	4.23	4.01	4.01	4.08	4.31
1989	4.28	4.76	4.79	4.88	4.60	4.40	4.31	4.06	4.31	3.96	4.08	3.98	3.74
1988	5.15	5.86	5.46	5.46	5.15	5.22	4.91	4.99	5.04	4.96	4.93	5.13	5.03
1987	4.83	5.05	4.86	4.61	4.79	4.79	4.59	4.33	4.22	4.37	5.54	5.64	5.84
1986	5.70	5.99	6.01	5.83	5.97	5.74	5.57	6.06	5.35	5.49	5.53	5.40	5.52
1985	5.93	6.38	6.17	5.65	5.78	5.63	5.81	6.04	6.00	6.26	5.81	5.84	5.86
1984	6.55	6.13	6.51	6.26	6.23	6.49	6.77	7.10	6.59	6.46	6.68	6.76	6.64
1983	6.78	7.58	7.64	7.83	7.47	6.71	6.02	6.40	6.33	6.11	6.32	6.51	6.43
1982	7.80	7.20	7.88	7.57	7.48	7.65	8.16	8.98	8.20	7.78	7.46	7.79	7.68
1981	6.10	5.27	5.50	5.56	6.00	6.10	6.18	6.04	6.17	6.92	6.79	6.56	6.46
1980	5.50	5.58	5.45	6.65	6.43	6.06	5.71	5.60	5.75	5.42	5.28	4.34	4.74
1979	6.41	7.16	7.25	6.86	6.75	6.84	6.38	6.24	5.91	5.89	6.62	5.92	5.76
1978	6.79	6.71	6.77	6.62	6.40	6.43	6.54	6.61	6.64	6.65	7.34	7.33	7.49
1977	5.93	5.53	5.89	5.98	5.91	5.86	5.52	5.83	6.25	6.00	6.27	5.98	6.14
1976	6.32	6.48	6.68	6.63	6.76	6.61	6.23	6.20	6.25	6.09	6.26	5.99	5.55
1975	7.09	7.20	7.13	7.16	7.30	6.99	6.47	6.84	7.16	7.16	7.18	7.19	7.31
1974	7.55	6.00	6.20	6.33	7.08	7.63	8.02	8.06	9.22	9.22	8.45	8.05	7.92
1973	5.78	5.09	5.18	5.47	5.59	5.70	6.09	6.12	6.54	5.87	5.74	5.94	6.35
1972	5.37	5.31	5.48	5.44	5.62	5.62	5.71	5.70	5.36	5.40	5.23	4.96	4.83
1971	5.18	4.88	4.93	4.88	4.86	5.06	5.23	5.08	5.21	5.42	5.63	5.81	5.36
1970	5.51	5.86	5.48	5.36	5.67	6.11	6.11	5.76	5.43	5.43	5.01	5.32	4.98
1969	5.15	4.49	4.67	4.83	4.86	4.83	5.25	5.43	5.46	5.66	5.40	5.55	5.79
1968	4.72	4.76	4.91	5.14	5.03	4.90	4.62	4.66	4.72	4.65	4.61	4.36	4.39
1967	4.60	4.85	4.89	4.84	4.76	4.86	4.91	4.76	4.70	4.54	4.81	4.99	4.85
1966	4.57	4.12	4.31	4.37	4.39	4.50	4.61	4.76	5.06	5.25	4.99	4.99	5.01
1965	3.87	3.61	3.65	3.68	3.73	3.83	3.99	3.95	3.94	3.91	3.98	4.03	4.12
1964	3.89	3.98	4.05	4.07	3.97	3.98	3.96	3.83	3.85	3.86	3.82	3.69	3.67
1963	3.86	3.88	3.89	3.92	3.78	3.76	3.79	3.84	3.81	3.87	3.88	3.98	3.95
1962	4.00	3.75	3.68	3.65	3.67	4.10	4.38	4.21	4.13	4.32	4.33	3.92	3.91
1961	3.89	4.18	4.04	3.95	3.85	3.90	4.05	3.95	3.87	3.90	3.75	3.57	3.70
1960	4.48	4.49	4.54	4.48	4.45	4.62	4.54	4.53	4.29	4.51	4.62	4.40	4.25
1959	4.15	3.87	3.83	3.84	4.04	4.12	4.31	4.11	4.05	4.44	4.38	4.42	4.34
1958	4.52	4.95	5.02	4.94	4.65	4.54	4.48	4.47	4.40	4.33	4.25	4.21	3.97
1957	4.83	4.53	4.69	4.61	4.45	4.42	4.59	4.62	4.92	5.07	5.38	5.19	5.47
1956	4.67	4.71	4.71	4.66	4.72	4.75	4.64	4.36	4.47	4.72	4.71	4.81	4.75
1955	4.49	4.58	4.45	4.41	4.41	4.44	4.48	4.44	4.42	4.49	4.67	4.49	4.61
1954	4.86	5.07	5.10	5.04	4.90	4.77	4.81	4.81	4.80	4.75	4.93	4.75	4.64

EARNINGS - WEIGHTED AVERAGE - $ PER SHARE

	Gas Transm.	Gas Distrib	Natural Gas
2000			
1Q	8.52	6.25	0.86
2Q	10.17	1.57	0.27
3Q	5.66	1.81	0.40
4Q	34.22	10.79	1.92
1999			
1Q	24.09	4.60	14.79
2Q	27.16	4.87	15.50
3Q	31.17	6.70	17.96
4Q	27.36	9.63	1.38
1998			
1Q	19.23	11.19	13.39
2Q	26.53	11.56	15.81
3Q	29.24	11.03	16.68
4Q	28.41	4.27	14.25
1997			
1Q	29.73	11.87	16.00
2Q	21.49	12.11	13.63
3Q	19.95	12.64	14.48
4Q	18.60	11.87	13.45
1996			
1Q	26.58	12.10	15.33
2Q	27.44	12.48	16.29
3Q	27.01	12.37	16.17
4Q	29.99	12.29	17.50
1995			
1Q	37.88	10.21	17.96
2Q	38.53	8.67	17.69
3Q	41.07	8.32	18.43
4Q	41.74	10.80	18.98
1994			
1Q	19.77	7.57	11.47
2Q	19.39	9.02	11.94
3Q	23.36	10.27	13.71
4Q	20.58	10.04	12.43
1993			
1Q	15.72	10.49	8.01
2Q	17.30	10.33	9.61
3Q	14.78	10.19	8.81
4Q	18.25	10.36	11.86
1992			
1Q	5.13	8.41	5.03
2Q	7.12	8.50	5.80
3Q	9.96	8.04	6.50
4Q	11.50	9.13	8.53
1991			
1Q	7.98	8.86	7.39
2Q	7.57	8.62	8.90
3Q	□6.94	8.58	7.63
4Q	7.35	8.31	7.13
1990			
1Q	15. 9	8.48	10.59
2Q	14.98	□8.34	8.58
3Q	15.30	7.80	10.14
4Q	□7.71	7.62	□6.91
1989			
1Q	3.38	9.07	6.09
2Q	3.92	9.14	6.33
3Q	7.18	9.10	7.22
4Q	14.74	9.50	10.89

1988			
1Q	5.90	9.26	8.02
2Q	6.99	9.22	8.26
3Q	5.78	9.19	6.53
4Q	3.06	9.37	6.25
1987			
1Q	d10.45	8.35	3.62
2Q	d3.16	8.37	3.26
3Q	d3.19	7.83	3.06
4Q	3.82	8.00	6.45
1986			
1Q	6.89	6.18	5.94
2Q	d2.06	6.23	2.03
3Q	d3.72	6.84	1.80
4Q	d9.68	6.93	d0.19
1985			
1Q	15.41	3.23	10.71
2Q	13.70	2.43	9.48
3Q	11.88	2.08	8.70
4Q	8.48	7.42	7.59
1984			
1Q	16.85	9.21	14.11
2Q	17.90	9.89	14.73
3Q	17.64	9.36	14.06
4Q	17.01	2.58	12.46
1983			
1Q	18.54	6.99	13.79
2Q	16.99	6.34	13.11
3Q	15.69	5.67	12.42
4Q	16.00	6.88	13.05
1982			
1Q	22.24	8.27	16.93
2Q	21.85	8.22	16.48
3Q	21.62	7.82	16.21
4Q	19.64	7.46	14.98
1981			
1Q	20.79	10.14	15.94
2Q	21.79	8.81	16.59
3Q	22.15	8.56	16.87
4Q	23.17	8.77	16.97
1980			
1Q	17.86	8.02	13.87
2Q	19.40	8.08	14.53
3Q	19.63	8.03	14.58
4Q	20.33	8.53	15.22
1979			
1Q	14.72	7.93	11.84
2Q	15.71	8.77	12.52
3Q	16.81	8.47	12.86
4Q	17.36	8.56	13.76
1978			
1Q	14.55	6.32	11.33
2Q	14.36	7.43	11.52
3Q	14.05	8.22	11.82
4Q	14.37	7.78	11.68
1977			
1Q	13.85	6.30	10.93
2Q	13.99	6.27	11.28
3Q	14.03	6.37	11.31
4Q	14.48	6.73	11.30

1976			
1Q	13.19	5.04	9.66
2Q	13.84	4.98	10.01
3Q	13.84	4.99	10.15
4Q	13.59	5.52	10.55
1975			
1Q	9.91	4.62	8.17
2Q	10.53	5.14	8.68
3Q	10.62	4.89	8.64
4Q	11.90	4.72	9.04
1974			
1Q	9.49	4.12	7.49
2Q	10.56	4.16	8.08
3Q	11.52	4.12	8.59
4Q	11.07	4.48	8.64
1973			
1Q	7.76	4.81	6.78
2Q	7.87	4.74	6.85
3Q	8.07	4.55	6.95
4Q	8.60	4.30	7.13
1972			
1Q	7.41	4.23	6.27
2Q	7.51	4.18	6.32
3Q	7.70	4.04	6.38
4Q	7.58	4.55	6.64
1971			
1Q	6.76	4.54	5.78
2Q	6.83	4.72	5.94
3Q	6.86	4.67	5.98
4Q	7.21	4.64	6.14
1970			
1Q	6.50	4.71	5.67
2Q	6.45	4.80	5.64
3Q	6.43	4.24	5.55
4Q	6.59	4.47	5.67
1969			
1Q	6.36	4.01	5.35
2Q	6.63	4.15	5.51
3Q	6.64	4.24	5.49
4Q	6.59	4.38	5.57
1968			
1Q	6.52	4.21	5.41
2Q	6.59	3.79	5.29
3Q	6.40	3.81	5.27
4Q	6.30	3.96	5.23
1967			
1Q	5.73	4.08	4.70
2Q	5.79	4.04	4.76
3Q	6.01	3.96	4.89
4Q	6.35	4.01	5.19
1966			
1Q	5.20	3.82	4.53
2Q	5.30	4.01	4.62
3Q	5.42	3.86	4.64
4Q	5.51	3.96	4.75
1965			
1Q	4.83	3.67	4.18
2Q	5.03	3.76	4.32
3Q	5.13	3.76	4.43
4Q	5.11	3.81	4.44

1964			
1Q	4.59	3.33	3.69
2Q	4.40	3.49	3.79
3Q	4.32	3.45	3.82
4Q	4.33	3.59	4.04
1963			
1Q	3.95	3.52	3.60
2Q	4.04	3.44	3.63
3Q	4.14	3.39	3.70
4Q	4.26	3.25	3.67
1962			
1Q	3.64	2.93	3.31
2Q	3.72	3.02	3.37
3Q	3.73	3.02	3.33
4Q	3.83	3.23	3.45
1961			
1Q	3.53	2.93	3.24
2Q	3.55	2.93	3.23
3Q	3.51	2.76	3.15
4Q	3.54	2.80	3.17
1960			
1Q	3.24	2.71	3.03
2Q	3.34	2.92	3.10
3Q	3.40	2.90	3.10
4Q	3.50	2.76	3.18
1959			
1Q	3.02	2.55	2.98
2Q	[illegible]	2.50	2.86
3Q	3.08	2.43	2.86
4Q	3.15	2.58	2.95
1958			
1Q	3.34	2.45	3.06
2Q	3.12	2.42	3.01
3Q	3.08	2.31	3.01
4Q	2.98	2.30	2.85
1957			
1Q	3.37	2.25	2.90
2Q	3.42	2.11	2.82
3Q	3.46	2.11	2.76
4Q	3.46	2.32	2.87

[1]Revised.
Note: Quarterly earnings are for 12 months ended Mar. 31, June 30, Sept. 30 and Dec. 31.

STOCKS USED IN NATURAL GAS INDUSTRY AVERAGES

TRANSMISSION	DISTRIBUTION	INTEGRATED
Enron Corp.	[1]AGL Resources, Inc.	National Fuel Gas Co.
[2]DukeEnergy, Inc	[3]KeySpan Corp.	ONEOK, Inc.
Williams Companies	Peoples Energy Corp	Questar Corp.
	Laclede Gas Co.	
	Northwest Natural Gas Co.	
	Washington Gas Light Co	

[1]Formerly: Atlantic Gas Light Co.
[2]PanEnergy Corp. merged with Duke Power to form the DukeEnergy, Inc
[3]Formerly: Brooklyn Union Gas Co.

SELECTED STATISTICS ON THE NATURAL GAS INDUSTRY

TRANSMISSION

	[6]Earnings $ per Share	[1]AFUDC per Share	[10]Dividend $ per Share	[3]Payout Ratio %	Book Value $ per Share [8]Incl Def. Taxes	Book Value $ per Share Excl Def Taxes	[4]Return on Equity	[5]Int. Cov. incl. AFUDC	[6]Int. Cov. excl. AFUDC	Capitalization Debt % Lg. Tm.	Capitalization Debt % [7]Sht. Tm.	Capitalization Pfd %	Capitalization Common & Surplus %
2000	0.98	......	2.2	2.24	234.64	145.53	6.73	21.57	21.57	63.39	7.02	0.79	28.81
1999	31.17	0.00	10.95	......	404.50	300.74	9.45	3.84	3.84	45.38	1.13	0.06	42.68
1998	28.41	0.00	10.95	38.54	363.44	257.67	11.03	3.30	3.30	49.49	1.50	0.89	48.11
1997	18.60	0.00	10.74	57.74	498.33	347.75	5.35	2.78	2.78	49.90	0.48	0.63	49.0
1996	29.99	0.00	10.13	33.78	274.28	163.57	18.34	3.54	3.54	56.35	1.1	1.2	41.4
1995	41.74	0.11	9.03	21.63	306.60	199.26	20.95	3.51	3.51	48.5	2.5	1.2	47.8
1994	20.58	0.29	8.26	40.1	244.52	150.65	13.7	2.34	2.32	56.1	3.3	1.1	39.5
1993	18.25	0.39	7.98	43.7	273.21	175.21	10.4	2.10	2.09	55.1	2.7	3.7	38.6
1992	11.50	0.47	7.11	61.8	260.31	168.15	6.8	1.32	1.30	57.9	2.8	2.4	36.8
1991	7.35	1.00	6.82	92.8	236.65	155.25	4.7	1.59	1.46	59.7	4.2	2.4	33.7
1990	7.84	0.89	7.16	91.3	257.93	168.20	4.7	1.40	1.35	54.4	7.3	4.2	33.7
1989	14.74	0.60	8.86	60.1	199.70	135.89	10.8	1.71	1.68	51.0	9.7	6.7	32.4
1988	3.06	0.46	8.86	...	176.52	115.86	2.6	1.06	1.03	53.4	7.2	3.6	35.9
1987	3.82	0.15	8.86		163.91	113.24	3.4	1.54	1.52	50.6	11.5	4.7	32.9
1986	d9.68	0.19	9.23		169.87	119.33	...	d0.09	d0.11	54.6	10.9	5.2	29.6
1985	8.48	0.13	9.91	...	219.80	149.23	5.6	1.80	1.50	46.1	13.9	4.9	34.0
1984	17.01	0.37	9.39	55.2	218.56	152.90	11.1	2.39	2.37	42.6	10.3	4.9	41.4
1983	16.00	0.36	8.89	55.5	192.89	136.50	11.7	2.42	2.40	40.5	6.1	6.4	47.0
1982	19.64	1.39	8.90	45.3	170.38	124.77	15.7	2.26	2.19	42.6	8.6	5.4	43.4
1981	23.17	1.31	8.29	35.8	160.14	120.38	19.2	2.68	2.61	42.7	9.4	4.9	43.0
1980	20.33	0.67	7.59	37.3	136.79	107.09	19.0	2.83	2.78	43.9	7.6	5.7	42.8
1979	17.36	0.62	7.00	40.3	125.34	97.98	17.7	3.48	3.43	42.9	9.4	5.3	42.3
1978	14.37	0.87	6.25	43.5	114.31	92.62	15.5	3.65	3.56	44.3	8.1	5.5	42.1
1977	14.48	1.17	5.64	39.0	110.44	91.06	15.9	3.87	3.75	45.0	6.9	4.9	43.2
1976	13.59	1.01	5.12	37.6	104.65	86.95	15.6	3.51	3.40	49.5	6.0	5.5	39.1
1975	11.90	1.00	4.78	40.2	97.04	81.09	14.7	3.28	3.18	48.5	9.8	5.3	36.4
1974	11.07	0.82	4.49	40.6	85.96	72.53	15.2	3.14	3.06	48.3	11.3	5.8	34.6
1973	8.60	0.52	4.26	49.5	75.72	64.85	13.2	2.68	2.61	50.4	9.8	6.3	33.4
1972	7.58	0.39	4.13	54.5	68.28	59.63	12.7	2.62	2.57	53.9	6.5	6.5	33.0
1971	7.21	0.49	4.02	55.8	62.27	55.20	13.6	2.46	2.39	54.9	7.2	6.5	31.4
1970	6.59	0.55	3.91	59.3	60.22	53.74	12.3	2.28	2.21	56.3	6.9	7.4	29.4
1969	6.59	0.73	3.77	57.2	53.68	47.65	13.8	2.36	2.25	56.0	9.7	7.3	27.0
1968	6.30	0.49	3.75	59.5	52.09	45.99	13.7	2.65	2.56	55.0	8.6	8.5	27.9
1967	6.35	0.37	3.61	56.9	48.57	42.71	14.9	2.65	2.58	54.5	8.9	9.1	27.5
1966	5.51	0.36	3.42	62.1	43.08	38.83	14.2	2.87	2.78	54.9	7.7	9.5	28.0
1965	[illegible]	0.29	3.28	64.2		37.03	13.8	3.02	2.95	57.1	5.5	9.2	28.3
1964	4.59	0.25	2.93	63.8		33.79	13.6	2.97	2.90	58.2	3.4	10.3	27.9
1963	4.26	0.23	2.82	66.2		31.91	13.4	3.10	3.04	55.9	7.5	10.4	26.2
1962	3.83	0.23	2.39	62.4	...	30.06	12.7	3.05	2.98	59.5	4.4	10.7	25.4
1961	3.54	0.20	2.83	79.9		30.86	11.5	3.26	3.19	58.3	4.4	10.1	27.3
1960	3.50	0.16	2.81	80.3		30.21	11.6	3.22	3.17	57.8	4.3	10.4	27.5
1959	3.15	0.38	2.54	80.6		27.45	11.5	3.04	2.91	60.4	5.0	10.7	23.8
1958	2.98	0.38	2.43	81.5		26.20	11.4	3.10	2.97	60.9	4.6	10.9	23.6
1957	3.46	0.38	2.31	66.8		25.54	13.5	3.32	3.18	62.3	4.1	10.6	23.1

DISTRIBUTION

	[6]Earnings $ per Share	[1]AFUDC per Share	[10]Dividend $ per Share	[3]Payout Ratio %	Book Value $ per Share [8]Incl Def. Taxes	Book Value $ per Share Excl Def Taxes	[4]Return on Equity	[5]Int. Cov. incl. AFUDC	[6]Int. Cov. excl. AFUDC	Capitalization Debt % Lg. Tm.	Capitalization Debt % [7]Sht. Tm.	Capitalization Pfd %	Capitalization Common & Surplus %
2000	**0.11**	**0.19**	**6.19**	**56.27**	**106.10**	**78.03**	**1.41**	**11.49**	**9.26**	**55.66**	**7.20**	**1.18**	**38.96**
1999	6.70	0.02	8.22		141.40	117.72	3.63	3.92	3.92	40.24	1.5	1.4	56.86
1998	4.27	0.25	8.13	190.40	155.22	132.16	3.23	2.99	2.95	37.45	5.7	1.3	55.6
1997	11.87	0.10	8.02	67.6	119.75	91.80	12.9	4.06	4.04	42.8	2.1	1.9	53.2
1996	12.29	0.03	7.91	64.4	106.19	79.41	15.5	4.28	4.27	43.9	3.7	2.1	50.3
1995	10.80		7.56	70.0	105.19	80.59	13.4	3.14	3.14	44.0	3.8	2.0	50.1
1994	10.04[13]		7.44	74.1	108.89	83.49	12.0	3.51	3.51	45.1	4.2	2.2	48.6
1993	10.36	0.02	7.30	70.5	105.70	87.11	11.9	3.59	3.59	42.1	6.5	1.8	49.6
1992	9.13	0.06	7.14	78.2	105.96	83.13	11.0	4.04	4.03	40.8	7.7	2.0	49.4
1991	8.31	0.06	6.99	84.1	103.19	81.03	[12]10.3	3.77	3.76	45.1	4.1	2.8	48.0
1990	7.62	0.10	6.84	89.8	115.48	90.54	8.4	3.14	3.11	40.2	6.2	3.9	49.7
1989	9.50	0.27	6.58	69.3	91.29	71.62	13.3	3.33	3.29	42.3	4.7	3.4	49.5
1988	9.37	0.29	6.30	67.2	87.73	68.52	13.7	3.60	3.54	41.4	4.2	3.9	50.5
1987	8.00	0.18	6.02	75.3	84.92	63.57	12.6	3.62	3.58	39.8	7.1	3.2	49.8
1986	6.93	0.17	5.71	82.4	80.21	61.02	12.4	3.52	3.49	42.0	3.5	4.2	50.1
1985	7.42	0.10	6.22	83.8	82.55	58.57	12.7	3.34	3.31	39.9	5.0	5.1	49.8
1984	2.58	0.05	5.88		87.53	61.56	4.2	3.62	3.61	39.1	4.3	6.6	49.5
1983	6.88	0.04	5.55	80.7	92.57	64.34	10.7	2.84	2.84	42.0	5.2	7.3	45.5
1982	7.46	0.06	5.39	72.3	94.97	67.60	11.0	2.55	2.54	41.6	8.7	7.3	42.4
1981	8.77	0.04	5.11	58.3	90.00	65.41	13.4	3.04	3.03	40.0	10.2	7.9	41.9
1980	8.53	0.08	4.68	54.9	86.62	64.64	13.2	3.65	3.63	37.7	9.8	9.0	43.5
1979	8.56	0.13	4.44	51.9	74.08	60.18	14.2	4.21	4.19	40.0	7.1	9.8	43.1
1978	7.78	0.08	4.18	53.7	69.92	57.33	15.2	4.18	4.17	45.1	3.2	10.3	41.3
1977	6.73	0.11	3.93	58.4	57.90	49.12	13.6	3.76	3.74	47.2	3.8	9.9	39.1

1976	5.72	0.09	3.50	61.2	52.64	45.26	12.6	3.28	3.26	48.5	4.5	9.4	37.6
1975	4.95	0.08	3.39	68.5	49.20	42.97	11.5	2.97	2.95	48.0	6.9	8.8	36.4
1974	4.88	0.20	3.29	67.4	46.09	40.99	11.9	2.65	2.57	46.6	9.4	8.3	35.8
1973	4.76	0.20	3.28	68.9	44.99	41.33	11.5	3.21	3.15	47.9	5.9	8.5	37.6
1972	4.77	0.09	3.11	65.2	40.86	37.83	12.6	3.49	3.46	49.6	4.4	9.1	36.9
1971	4.66	0.09	3.05	65.5	39.62	37.77	12.3	3.56	3.53	49.8	3.8	9.9	36.6
1970	4.39	0.09	2.97	67.7	37.00	34.33	12.8	3.66	3.63	49.6	6.3	9.4	34.7
1969	4.24	0.07	2.89	66.6	35.79	33.14	13.1	4.01	3.98	47.1	8.0	10.1	34.7
1968	3.97	0.07	2.79	72.1	36.08	33.40	11.9	4.48	4.45	49.1	5.5	7.9	37.5
1967	4.04	0.06	2.71	67.1	33.35	31.67	12.8	4.73	4.69	48.7	5.4	8.8	37.1
1966	3.96	0.08	2.56	64.6	32.49	30.20	13.1	5.06	5.02	48.7	5.3	8.5	37.4
1965	3.76	0.05	2.41	64.1	......	29.47	12.8	5.43	5.39	48.0	4.5	9.3	38.2
1964	3.57	0.03	2.24	62.7	......	27.14	13.2	5.75	5.73	46.5	6.8	8.5	38.1
1963	3.20	0.04	2.11	65.9	......	25.90	12.4	5.96	5.93	48.3	3.2	9.2	39.3
1962	3.23	0.03	1.97	61.0	......	24.66	13.1	6.37	6.34	45.8	4.6	9.8	39.9
1961	2.78	0.04	1.89	68.0	......	23.84	11.7	6.38	6.34	47.9	1.9	8.9	41.3
1960	2.77	0.05	1.78	64.3	......	22.00	12.6	6.52	6.48	47.5	3.9	9.5	39.1
1959	2.57	0.03	1.63	63.4	......	20.81	12.3	6.56	6.52	46.8	7.2	6.6	39.4
1958	2.28	0.02	1.52	66.7	......	19.72	11.6	6.13	6.11	49.9	2.3	6.4	41.4
1957	2.25	0.02	1.41	62.7	......	19.07	11.8	5.90	5.88	49.7	5.7	3.6	40.9
					NATURAL GAS								
2000	**0.42**	......	**3.20**	**7.62**	**121.5**	**74.98**	**0.56**	**20.29**	**20.29**	**63.15**	**4.63**	......	**32.22**
1999	17.96	0.01	7.72	......	234.41	179.36	7.94	3.86	3.86	44.2	9.7	0.7	45.4
1998	14.25	0.18	7.68	53.89	204.45	204.45	8.31	3.30	3.29	45.9	2.8	0.8	50.4
1997	13.45	0.07	7.10	50.56	253.18	182.56	7.37	3.19	3.18	46.6	2.1	0.8	50.5
1996	17.50	0.03	6.80	38.9	167.40	111.83	15.7	3.63	3.63	48.9	2.5	1.5	44.4
1995	18.98	0.08	6.35	33.5	176.04	122.77	15.5	3.16	3.15	46.5	2.7	2.1	48.7
1994	12.43	0.14	6.01	48.4	151.58	103.56	12.0	2.63	2.61	50.7	4.2	2.5	42.6
1993	11.86	0.20	5.82	49.1	156.52	111.10	10.7	2.87	2.86	50.0	4.7	2.7	42.6
1992	8.53	0.27	5.15	60.4	157.28	110.48	7.7	2.98	2.95	51.9	4.9	2.9	40.3
1991	7.13	0.51	6.32	88.6	162.71	113.06	6.3	2.86	2.79	53.5	4.9	3.0	38.7
1990	6.94	0.44	7.03	......	180.64	125.17	5.5	2.29	2.24	44.5	9.1	3.8	42.4
1989	10.89	0.53	7.38	67.8	148.21	104.20	10.5	2.47	2.43	43.3	9.8	4.4	42.3
1988	6.25	0.40	7.20	......	141.92	96.82	6.5	2.35	2.30	44.2	8.1	3.5	44.2
1987	6.45	0.19	7.51	......	138.44	96.40	6.7	2.63	2.59	42.8	9.9	3.8	43.5
1986	d0.19	0.21	7.59	......	142.34	100.81	......	2.13	2.09	45.3	9.0	4.0	42.2
1985	7.59	0.20	8.12	......	161.70	110.96	6.8	2.99	2.93	41.7	9.3	4.4	44.4
1984	12.44	0.22	7.71	61.9	158.60	113.18	11.0	3.71	2.69	40.5	7.1	5.2	47.1
1983	13.05	0.31	7.29	55.9	149.37	107.80	12.1	2.67	2.65	40.3	6.2	5.5	48.0
1982	14.98	0.96	7.14	47.7	136.47	100.22	14.9	2.41	2.34	42.1	10.0	4.9	43.0
1981	16.97	0.95	6.91	45.4	132.85	100.24	16.9	2.80	2.73	41.6	10.2	4.6	43.6
1980	15.22	0.62	6.45	49.4	118.49	91.94	16.6	2.94	2.93	43.0	7.3	5.7	43.9
1979	13.76	0.56	5.97	43.4	107.24	84.64	16.3	3.51	3.45	43.2	8.6	5.6	42.6
1978	11.68	0.72	5.43	46.4	99.22	81.02	14.4	3.71	3.62	44.0	7.3	5.8	42.9
1977	11.30	0.86	4.96	43.9	94.23	78.47	14.4	3.71	3.60	45.4	6.4	5.4	42.8
1976	10.60	0.70	4.51	42.5	80.66	72.89	14.5	3.41	3.31	49.2	5.5	5.6	39.7
1975	9.08	0.66	4.21	46.6	75.01	68.15	13.3	3.14	3.06	48.5	8.9	5.1	37.4
1974	8.71	0.50	3.81	43.7	65.43	59.97	14.6	3.00	2.93	48.4	10.0	4.8	36.7
1973	7.18	0.36	3.75	52.2	62.60	57.92	12.4	2.85	2.79	50.1	8.4	5.0	36.4
1972	6.69	0.25	3.60	53.8	57.39	53.65	12.5	2.92	2.87	52.8	6.2	5.1	36.0
1971	6.20	0.28	3.50	56.5	53.51	50.43	12.3	2.80	2.74	52.4	7.2	5.2	35.2
1970	5.71	0.31	3.40	59.5	51.18	48.48	11.8	2.71	2.65	53.3	6.5	5.7	34.2
1969	5.61	0.38	3.27	58.3	47.51	45.00	12.5	2.88	2.79	52.1	9.2	5.7	33.0
1968	5.28	0.26	3.23	61.2	45.68	43.17	12.2	3.18	3.10	52.9	6.8	6.0	34.3
1967	5.24	0.22	3.11	59.4	43.10	40.73	12.9	3.38	3.31	52.3	6.8	6.4	34.5
1966	4.78	0.19	2.92	61.1	38.04	35.66	13.4	3.68	3.60	52.3	6.0	6.5	35.1
1965	4.46	0.15	2.74	61.4		31.85	14.0	3.94	3.87	54.7	4.5	6.6	34.2
1964	4.06	0.12	2.55	62.8		32.05	12.7	3.95	3.90	53.2	4.0	7.1	35.8
1963	3.69	0.10	2.44	66.1		30.40	12.1	3.98	3.93	52.4	5.5	7.3	34.9
1962	3.47	0.10	2.20	63.4		29.12	11.9	3.99	3.95	54.1	4.0	7.5	34.4
1961	3.18	0.09	2.30	72.3		28.40	11.2	4.08	4.03	54.0	3.8	7.2	35.0
1960	3.20	0.10	2.27	70.9		25.59	12.5	4.17	4.12	57.7	4.4	8.0	34.3
1959	2.96	0.16	2.04	68.9		25.64	11.5	4.03	3.94	55.3	4.6	7.4	32.7
1958	2.86	0.17	1.99	69.6		24.94	11.5	3.96	3.86	56.1	4.4	7.6	31.9
1957	2.89	0.16	1.87	64.7	.....	23.34	12.4	4.17	4.07	56.9	4.0	7.4	31.7

[1]Allowance for funds used during construction per year-end weighted share of commonstock [2]Dividends per share divided by earnings per share. [3]Deferred taxes consists of deferred income taxes and deferred investment tax credits [4]Consists of earnings per share divided by year-end book value per share, excluding deferred income taxes [5]Consists of net operating income plus federal and state income taxes, deferred income taxes, deferred investment tax credits, and allowance for funds used during construction, divided by total interest charges [6]Same as [5] but excluding allowance for funds used during construction [7]Includes current maturities. [8]Consists of net income plus depreciation, deferred income taxes, deferred investment tax credits, less allowance for funds used during construction and dividends on preferred and common stock [9]Consists of construction expenditures net of allowance for funds used during construction [10]Year end [11]Revised [12]Less than 0.01 [13]Third quarter earnings

Note: The above annual gas industry statistics are not entirely comparable to Moody's gas stock averages because the latter has had companies added and deleted between 1955-1977, whereas the former consisted of the same companies for this period of time Except for the exclusion of Mountain Fuel Supply and South Jersey Industries and the inclusion of Northwest Natural Gas in the distribution group and the exclusion of Equitable Gas in the integrated gas group from the gas industry series, the composition of companies and the method of computation are the same as Moody's gas stock averages

A NATION-WIDE SURVEY OF PUBLIC UTILITY PROGRESS

INTRODUCTION

Moody's annual survey of the nation's public utilities is designed to update the fixed-income investor on the key economic, financial and regulatory developments affecting the credit quality of utility investments In line with the longer-term perspective of most fixed-income investors, we have also provided comprehensive historical data to facilitate the analysis of major trends This information is presented for electric utilities, as well as for companies in the gas business and public communications.

Fundamental economic statistics for each public utility sector include aggregate industry sales figures, with a breakdown by customer classifications For the electric utilities, we enumerate the trends in regional fuel costs and recent additions to the industry's generating capability Aggregate annual construction outlays are also included For the gas industry, Moody's reports on annual production levels, as well as reserve additions and revisions, the trend in gas costs, and the nation's over-all storage capacity Detailed statistics on the telephone industry have also been compiled.

The public utility sector, for the most part, continues to be one of the most highly regulated areas in American business Moody's outlines the history and authority of the most prominent federal agencies with jurisdiction over utilities, including the Department of Energy, the Federal Energy Regulatory Commission and the Nuclear Regulatory Commission The Public Utility Holding Company Act of 1935, administered by the Securities and Exchange Commission, is discussed In addition, we provide an update on the activities of the Rural Electrification Administration and agencies, like the Bonneville Power Administration, that are directly involved in energy production

The extensive financial section includes aggregate income statement information for each public utility sector, as well as composite balance sheet data in selected accounts For the gas industry, these items have been segmented for the transmission, distribution and integrated companies We have also presented a full array of important operating and financial ratios for each energy sector, including depreciation rates, interest coverages, and effective tax rates And, the tables and charts on the following pages detail Moody's compilation of public utility bond yields, preferred stock returns, and a wide range of common stock measures for the equity investor

THE ELECTRIC LIGHT AND POWER INDUSTRY

INSTALLED CAPACITY OF ELECTRIC GENERATING PLANTS BY CLASS OF OWNERSHIP ALL TYPES OF PRIME MOVERS

Source: EDISON ELECTRIC INSTITUTE

(Kilowatts)

Year	Total All Plants	Privately Owned Utilities	Cooperatives	Municipal Utilities	Federal	State Projects Power Districts	Subtotal Publicly Owned
1934	34,118,741	31,547,337	[1]	2,102,000	287,777	182,385	2,571,404
1935	34,435,768	31,820,357	[1]	2,140,000	299,641	175,485	2,615,411
1936	35,081,569	31,786,653	[1]	2,307,000	803,613	183,910	3,294,916
1937	35,620,011	31,958,043	[1]	2,622,000	832,530	206,825	3,661,968
1938	37,492,095	33,246,341	[1]	2,780,000	1,156,080	309,737	4,245,754
1939	38,862,716	33,907,963	[1]	2,971,000	1,650,325	333,382	4,954,753
1940	39,926,881	34,398,576	[1]	3,150,000	1,944,000	434,696	5,528,305
1941	42,405,436	36,041,274	[1]	3,327,000	2,370,817	666,429	6,364,162
1942	45,052,950	37,441,750	[1]	3,527,000	3,216,357	867,717	7,611,200
1943	47,950,767	39,127,827	[1]	3,618,000	4,321,857	882,877	8,822,940
1944	49,189,072	39,732,752	[1]	3,684,000	4,886,032	886,358	9,456,319
1945	50,110,928	40,307,179	[1]	3,831,000	5,081,172	891,132	9,803,749
1946	50,316,621	40,334,545	[1]	3,961,000	4,919,572	1,101,503	9,982,076
1947	52,322,007	41,986,482	167,000	4,082,000	5,027,384	1,059,000	10,335,384
1948	56,559,838	45,380,885	200,000	4,361,000	5,525,302	1,092,000	11,178,302
1949	63,100,334	50,483,971	238,000	4,990,000	6,209,652	1,178,000	12,615,652
1950	68,919,040	55,175,623	312,000	5,284,000	6,921,152	1,227,000	13,744,152
1951	75,775,000	60,192,000	491,000	5,609,000	8,098,552	1,384,000	15,583,552
1952	82,226,000	64,349,000	532,000	6,019,000	9,678,000	1,648,000	17,877,000
1953	91,502,000	71,201,000	600,000	6,569,000	11,358,000	1,774,000	20,301,000
1954	102,592,000	79,127,000	768,000	7,225,000	13,567,000	1,905,000	23,465,000
1955	114,472,000	86,887,000	800,000	7,795,000	16,962,000	2,028,000	27,585,000
1956	120,697,000	91,145,000	795,000	8,325,000	18,336,000	2,096,000	29,552,000
1957	129,123,000	97,376,000	924,000	8,640,000	19,649,000	2,534,000	31,747,000
1958	142,597,000	108,202,000	977,008	9,817,000	20,436,000	3,165,000	34,395,000
1959	156,841,000	118,999,000	1,136,000	10,914,000	21,874,000	3,918,000	37,842,000
1960	168,002,000	128,450,000	1,390,000	11,499,000	22,350,000	4,313,000	39,552,000
1961	180,668,000	136,749,000	1,446,000	12,205,000	23,257,000	7,011,000	43,919,000
1962	191,067,000	144,577,000	1,537,000	12,929,000	24,315,000	7,709,000	46,481,000
1963	210,549,000	158,448,000	1,873,000	14,222,000	27,315,000	8,691,000	52,101,000
1964	222,285,000	167,704,000	2,017,000	15,199,000	28,343,000	9,022,000	54,591,000
1965	236,127,000	177,570,000	2,309,000	15,407,000	31,690,000	9,151,000	58,557,000
1966	247,843,000	185,671,000	2,758,000	16,548,000	32,608,000	10,258,000	62,172,000
1967	269,252,000	203,580,000	3,019,000	18,049,000	33,640,000	10,964,000	65,672,000
1968	291,058,000	220,766,000	3,434,000	19,429,000	34,956,000	12,473,000	70,292,000
1969	313,349,000	240,078,000	4,318,000	20,035,000	36,130,000	12,788,000	73,271,000
1970	341,090,000	262,675,000	5,162,000	20,941,000	38,718,000	13,594,000	78,415,000
1971	367,396,000	286,879,000	5,418,000	21,788,000	39,654,000	13,657,000	80,517,000
1972	399,606,000	314,859,000	6,700,000	23,167,000	40,645,000	14,235,000	84,747,000
1973	439,875,000	346,476,000	7,288,000	24,956,000	44,520,000	16,635,000	93,399,000
1974	476,107,000	376,004,000	7,531,000	27,323,000	45,846,000	19,236,000	99,936,000
1975	508,414,000	399,036,000	9,136,000	28,787,000	50,133,000	21,322,000	100,242,000
1976	531,449,000	415,828,000	9,946,000	30,554,000	51,707,000	23,414,000	105,675,000
1977	560,361,000	438,385,000	10,889,000	33,291,000	53,183,000	24,163,000	111,087,000
1978	579,312,000	453,647,000	11,635,000	34,426,000	54,282,000	25,322,000	114,030,000
1979	598,443,000	464,144,000	13,837,000	34,525,000	58,346,000	27,591,000	120,462,000
1980	613,695,000	477,083,000	15,422,000	34,598,000	59,083,000	27,509,000	121,190,000
1981	634,808,000	490,767,000	18,406,000	35,125,000	60,982,000	29,527,000	125,635,000
1982	650,105,000	499,111,000	21,463,000	35,819,000	62,544,000	31,168,000	129,530,000
1983	658,182,000	505,487,000	22,202,000	36,598,000	62,973,000	30,923,000	130,493,000
1984	672,462,000	514,863,000	24,738,000	36,717,000	63,304,000	32,841,000	132,862,000
1985	688,733,000	530,405,000	24,574,000	37,017,000	63,710,000	33,027,000	133,754,000
1986	707,684,000	544,199,000	26,430,000	38,584,000	63,864,000	34,607,000	137,055,000
1987	718,056,000	552,795,000	26,359,000	39,378,000	64,666,000	34,858,000	138,902,000
1988	723,852,000	557,756,000	26,383,000	40,388,000	64,792,000	34,533,000	139,714,000
1989	730,883,000	562,127,000	26,358,000	40,668,000	67,193,000	34,537,000	142,399,000
1990	735,051,000	568,769,000	26,337,000	40,115,000	65,434,000	34,397,000	139,945,000
1991	739,957,000	573,023,000	26,453,000	40,424,000	65,561,000	34,496,000	140,481,000
1992	741,651,000	572,920,000	26,015,000	41,629,000	66,116,000	34,970,000	142,715,000
1993	744,689,000	575,163,000	26,107,000	41,789,000	66,129,000	35,501,000	143,419,000
1994	745,954,000	574,834,000	26,372,000	41,992,000	66,333,000	36,423,000	144,748,000
1995	750,541,000	578,668,000	27,120,000	42,179,000	65,937,000	36,638,000	144,754,000
[2]1996	756,481,000	582,214,000	27,195,000	43,035,000	67,151,000	36,887,000	147,072,000
[2]1997	759,875,000	582,508,000	27,999,000	43,762,000	68,868,000	36,738,000	149,368,000
[3]1998	728,259,000	531,267,000	32,523,000	50,548,000	68,652,000	45,270,000	164,470,000
[3]1999	677,955,000	483,746,000	34,612,000	50,184,000	68,675,000	40,738,000	159,597,000

[1]Prior to 1947 included in Power Districts and State Projects [2]Revised [3]Preliminary

Note: Data for 2000 not available

PRODUCTION OF ELECTRIC ENERGY BY CLASS OF OWNERSHIP - ALL TYPES OF PRIME MOVERS

Source: EDISON ELECTRIC INSTITUTE

(Millions of Kilowatt-hours)

Year	Total All Plants	Privately Owned Utilities	Cooperatives	Municipal Utilities	Federal	State Projects Power Districts	Subtotal Publicly Owned
1932	79,393	74,488	[1]	3,888	435	572	4,905
1933	81,740	76,688	[1]	3,960	458	654	5,072
1934	87,258	82,079	[1]	4,257	357	565	5,179
1935	95,287	89,330	[1]	4,670	555	732	5,958
1936	109,316	102,293	[1]	5,149	1,072	801	7,023
1937	118,913	110,464	[1]	5,743	1,843	863	8,449
1938	113,812	104,090	[1]	5,699	3,028	994	9,722
1939	127,642	115,078	[1]	6,144	5,475	944	12,564
1940	141,837	125,411	[1]	6,677	8,584	1,175	16,426
1941	164,788	144,290	[1]	7,512	10,794	2,192	20,498
1942	185,979	158,052	[1]	8,185	16,893	2,848	27,928
1943	217,759	180,247	[1]	9,871	24,485	3,156	37,511
1944	228,189	185,850	[1]	10,407	28,866	3,065	42,339
1945	222,486	180,926	[1]	10,414	28,001	3,146	41,560
1946	223,178	181,020	[1]	11,600	26,960	3,598	42,158
1947	255,739	208,105	406	13,246	29,877	4,104	47,633
1948	282,698	228,231	652	13,961	35,373	4,481	54,467
1949	291,100	233,112	766	14,242	38,102	4,877	57,987
1950	329,141	266,860	989	16,101	40,388	4,804	62,282
1951	370,673	301,845	1,266	18,504	44,120	4,938	68,828
1952	399,224	322,126	1,526	17,490	52,492	5,590	77,098
1953	442,665	354,272	1,897	21,625	58,064	6,807	88,393
1954	471,686	370,970	2,476	23,505	67,804	6,931	100,716
1955	547,038	420,869	3,044	25,852	89,064	8,209	126,169
1956	600,668	459,015	3,413	28,005	100,711	9,524	141,653
1957	631,507	480,943	3,029	27,851	109,175	10,509	150,564
1958	645,098	490,402	3,122	28,329	110,437	12,508	154,696
1959	710,861	544,234	4,304	24,618	109,052	17,698	155,772
1960	753,350	578,600	4,962	36,924	112,321	20,543	174,750
1961	792,039	604,883	5,241	38,753	112,177	30,985	187,156

1962	852,314	651,016	6,063	41,688	115,776	37,771	201,298
1963	916,793	701,253	6,949	46,293	124,340	37,958	208,591
1964	983,990	756,183	7,934	49,813	129,936	39,674	219,873
1965	1,055,252	809,474	8,571	49,940	145,231	42,036	237,207
1966	1,144,350	880,837	11,175	52,627	153,067	46,644	252,338
1967	1,214,365	928,439	12,389	57,788	162,399	53,350	285,926
1968	1,329,443	1,019,313	14,140	63,804	170,834	61,352	395,990
1969	1,442,182	1,102,162	17,513	69,614	183,245	69,648	322,507
1970	1,531,609	1,183,190	23,459	71,394	185,753	67,813	324,960
1971	1,613,936	1,250,005	27,228	72,535	194,490	69,678	336,703
1972	1,747,323	1,356,677	31,610	78,922	206,736	73,378	390,646
1973	1,856,216	1,448,860	35,127	80,872	211,715	79,642	405,356
1974	1,867,000	1,442,000	34,000	79,000	220,000	92,000	391,000
1975	1,917,619	1,486,844	35,328	81,518	221,226	92,703	395,447
1976	2,036,503	1,582,022	40,549	77,806	235,908	100,218	413,932
1977	2,124,166	1,684,084	41,884	83,382	213,633	98,183	395,198
1978	2,206,448	1,721,163	48,717	89,700	235,257	111,476	436,433
1979	2,247,359	1,756,170	54,404	87,265	235,570	113,950	436,785
1980	2,286,414	1,782,933	63,550	86,579	235,051	118,301	439,931
1981	2,294,812	1,785,500	73,314	80,701	232,222	123,075	435,998
1982	2,241,211	1,711,576	77,098	76,569	241,004	134,964	452,537
1983	2,310,285	1,764,080	84,710	73,069	258,181	130,245	461,495
1984	2,416,304	1,848,916	101,970	74,672	253,928	136,818	465,418
1985	2,469,841	1,918,032	108,321	73,864	233,063	136,560	443,488
1986	2,487,310	1,928,199	113,897	78,869	224,854	141,491	445,214
1987	2,572,127	2,022,260	122,508	86,211	205,363	135,786	427,359
1988	2,704,250	2,145,601	123,079	96,539	201,125	137,907	435,571
1989	2,784,304	2,189,941	122,810	100,311	223,531	145,712	469,554
1990	2,808,151	2,202,553	126,115	97,652	235,272	146,559	479,483
1991	2,825,023	2,215,116	127,689	96,590	241,104	144,524	482,218
1992	2,797,219	2,214,475	127,405	94,414	224,695	136,231	455,339
1993	2,882,525	2,271,185	127,738	103,076	232,110	148,416	483,602
1994	2,910,712	2,308,684	131,954	98,804	230,433	140,837	470,074
1995	2,994,529	2,340,482	134,103	103,420	263,205	153,319	519,944
1996	3,073,149	2,372,985	138,753	101,595	297,716	162,099	561,411
1997	3,119,098	2,385,484	141,356	111,133	312,120	169,004	592,258
[2]1998	3,212,171	2,350,414	195,756	167,880	288,506	209,613	666,000

[1]Prior to 1947 included with Power Districts & State Projects
[2]Revised
Note: Data for 2000 not available.

ENERGY SALES - BY CLASS OF SERVICE - (Total Industry)

Source: EDISON ELECTRIC INSTITUTE

(In Millions of Kilowatt-Hours)

	1999	[1]1998	1997	1996	1995	1994	1993	1992	1991
[1]Residential	1,140,761	1,127,735	1,078,605	1,082,358	1,042,399	1,008,492	994,144	929,290
Comm'l (small lt. & pwr.)	970,601	968,528	929,031	887,086	863,501	833,508	803,094	755,658
Industrial (large lt. & pwr.)	1,017,783	1,040,038	1,027,667	1,028,427	1,006,178	990,254	956,611	949,259
Street and highway lighting	15,894	16,282	19,739	18,037	17,887	18,462	18,134	15,795
Railroad and railways	N.A.	N.A.	5,321	5,302	5,481	5,788	5,376	5,166
Electrified & steam railroads								
Municipal and miscellaneous	N.A.	N.A.	78,240	72,774	72,023	73,557	72,396	79,762
Total	3,145,039	3,152,583	3,138,604	3,093,984	3,007,469	2,930,063	2,849,755	2,734,930

[1]Revised
Note: Commercial and Industrial are not wholly comparable on a year-to-year basis due to changes from one classification to another
Note: Total may not equal sum of components due to independent rounding
Note: Data for 2000 not available

REVENUES - TOTAL ELECTRIC UTILITY INDUSTRY - (By Year and Class of Service)

Source: EDISON ELECTRIC INSTITUTE

(000's omitted)

	1999	1998	1997	1996	1995	1994	1993	1992	1991	1990
[1]Residential	$93,142,367	$93,166,443	$90,881,203	$90,465,389	$87,597,523	$81,517,347	$82,436,503	$76,392,219	$76,350,757
Comm'l (small lt. & pwr.)	70,492,058	71,772,470	70,458,832	67,801,618	66,477,471	64,432,340	62,040,225	57,969,047	56,847,134
Industrial (large lt. & pwr.)	45,055,529	46,560,216	46,690,273	47,358,592	46,913,380	46,816,060	46,591,203	46,760,653	45,869,777
Municipal street lighting	1,809,785	1,875,735	2,184,639	1,836,493	1,962,316	2,024,512	2,031,192	1,739,072	1,689,600
Street & interurban elec. railways	N.A.	N.A.	376,108	361,507	376,718	416,269	382,505	363,087	338,050
Municipal & miscellaneous	N.A.	N.A.	4,555,995	4,469,588	4,231,110	4,308,915	4,375,624	4,058,990	4,022,347
Tot. rev. fr. ultimate cons.	[2]$210,499,739	[2]$218,362,586	[2]$215,147,050	$212,293,187	$207,558,519	$202,515,442	$197,857,252	$187,283,068	$185,117,665

[1]Revised to allocate "Rural" to other appropriate classes of service [2]Preliminary
Note: Total may not equal sum of components due to independent rounding
Note: The above revenue breakdown for each class of customers is very instructive not only when related to total income for each year, but also when compared with the table giving the kwh consumption for the same period for each class of ultimate consumer. A characteristic of residential sales growth has been its uniformity. Industrial sales are more sensitive to fluctuations in our national economy and have expanded less uniformly. The relative size of each of the three major consumption categories is also shown below. Data for 2000 not available.

Residential & Rural Commercial Industrial
Year %
Total Sales %
Total Revenues %
Total Sales %
Total Revenues %
Total Sales %
Total Revenues

1999	35.3	30.0	31.4	33.2	32.7	20.9
1998	34.8	29.9	32.1	42.7	32.9	21.3
1997	34.4	29.6	32.7	42.2	32.7	21.7
1996	33.0	31.3	33.1	42.6	31.9	22.3
1995	34.7	28.7	33.5	42.2	32.0	22.6
1994	34.4	28.5	33.8	41.7	31.8	23.1
[1]1993	34.9	28.2	33.6	41.7	31.3	23.5
1992	34.0	27.6	34.7	40.8	31.0	25.0
1991	34.7	41.2	23.5	40.2	34.1	24.8
1990	34.1	40.7	27.5	30.7	34.7	25.4
1989	34.3	40.5	27.3	30.4	34.8	25.8
1988	34.7	40.9	27.3	30.3	34.5	25.6
1987	34.8	40.5	27.0	30.0	34.6	26.1
1986	34.8	40.0	26.7	29.8	34.8	26.8
1985	34.1	39.3	26.3	29.5	35.6	27.8
1984	34.1	39.3	25.4	28.8	36.6	28.5
1983	34.7	39.5	25.3	28.6	36.3	28.3
1982	34.9	38.8	24.6	28.1	36.7	29.5
1981	34.0	38.6	24.3	26.2	38.1	29.7
1980	34.5	39.4	24.7	28.7	37.4	28.6
1979	34.1	38.7	23.7	28.0	39.2	29.9
1978	33.6	9.2	23.8	28.2	38.8	29.0
1977	33.4	39.4	24.3	28.8	38.8	28.2
1976	33.4	39.6	23.8	28.5	39.2	28.1
1975	33.8	40.4	24.1	28.8	38.2	27.1
1974	32.6	40.4	23.1	28.6	40.5	27.3
1973	32.5	41.7	23.3	28.9	40.3	25.5
1972	32.4	42.0	22.9	28.8	40.5	25.0
1971	32.7	42.4	22.8	28.6	40.4	24.8
1970	32.2	42.7	22.5	28.5	41.1	24.6
1969	31.2	42.1	21.9	28.3	42.6	25.0
1968	30.6	42.0	22.1	28.6	43.2	25.1
1967	29.9	41.7	21.9	28.7	43.9	25.3
1966	29.5	41.6	21.7	28.7	44.8	25.5
1965	29.5	41.8	21.2	28.5	44.5	25.6
1964	29.4	41.1	20.6	27.4	46.0	25.4
1963	29.1	41.8	20.0	27.7	46.7	26.3
1962	29.2	41.9	18.6	26.2	48.2	27.6
1961	29.0	42.0	18.7	26.1	48.2	27.7
1960	28.7	42.2	16.8	24.6	50.5	28.9
1959	28.7	42.7	17.4	24.6	50.0	28.4
1958	29.0	43.0	17.2	24.4	49.9	28.4
1957	27.4	42.1	16.1	24.1	52.3	29.7
1956	26.2	41.6	15.9	24.0	53.9	30.2
1955	26.1	41.1	16.2	24.2	53.6	30.1
1954	27.5	41.9	18.3	25.9	49.6	27.9
1953	26.3	41.9	18.4	26.2	50.4	28.4
1952	27.8	42.1	18.1	25.8	48.9	27.4
1951	24.2	41.4	18.0	25.9	49.6	27.8
1950	26.5	41.1	18.0	26.2	49.6	27.4
1949	26.4	40.7	18.6	26.6	48.6	27.4
1948	23.8	38.8	17.9	26.7	51.5	29.0
1947	20.3	35.5	17.6	26.8	52.2	28.7
1946	20.2	35.9	17.3	26.7	51.8	28.0
1945	19.6	37.6	15.7	25.4	55.5	30.0
1944	17.5	36.0	15.1	24.9	58.1	31.8
1943	17.6	35.9	15.5	25.2	56.8	31.2
1942	16.9	34.6	17.1	26.8	55.6	29.0
1941	17.9	35.2	17.6	27.2	54.3	28.4
1940	19.2	36.7	18.8	28.2	50.3	25.9
1939	20.0	36.8	19.6	28.9	48.3	25.0
1938	20.7	37.3	20.4	29.3	46.1	24.0
1937	17.8	35.1	18.2	28.5	51.7	26.9
1936	17.4	35.7	17.4	27.5	51.0	28.4
1935	18.0	36.6	17.5	27.1	52.8	27.3

Note: The above table is derived from the two preceding and shows the proportions of total k.w.h. sales and revenues derived from each of the three main customer groups. It is of particular value as a basis for comparing the diversification of an individual company's sales and revenues. [1]Revised. 1953-1965 have been revised to allocate rural sales and revenues to other appropriate classes of service. Data for 2000 not available

ULTIMATE CUSTOMERS - BY YEARS AND CLASSES OF SERVICE

Source: EDISON ELECTRIC INSTITUTE

As of Dec. 31	Residential	Commercial	Industrial	Other	Total
1999	109,817,057	13,963,937	527,329	380,968	124,689,291
[1][2]1998	108,736,845	13,832,662	538,167	368,028	123,475,702
[1]1997	107,093,501	13,527,117	562,862	971,407	122,154,887
[1]1996	105,334,712	13,190,904	585,019	884,578	119,995,213
[1]1995	103,804,131	12,922,598	572,466	880,810	118,180,005
1994	102,729,353	12,763,940	567,801	846,118	116,907,312
1993	101,307,528	12,533,045	536,458	839,177	115,216,208
1992	99,635,244	12,461,309	529,701	453,939	113,080,193
1991	98,184,250	12,288,449	513,727	447,653	111,434,079
1990	97,033,887	12,135,373	508,145	424,645	110,102,079
1989	95,616,026	11,976,449	506,597	369,142	108,468,242
1988	93,921,875	11,637,444	491,292	360,617	106,411,256
1987	92,399,323	11,386,008	487,572	351,303	104,624,233
1986	90,994,586	11,114,300	498,254	345,625	102,952,793
1985	89,819,726	10,920,861	499,728	338,928	101,579,271
1984	87,938,995	10,565,239	525,692	341,071	99,371,026
1983	85,842,195	10,266,449	500,215	376,641	96,985,531
1982	84,371,779	9,976,274	533,635	368,549	95,250,268
1981	83,304,355	9,847,260	516,996	342,657	94,011,299
1980	82,153,162	9,698,809	484,652	316,818	92,653,471
1979	79,620,180	9,386,572	477,874	287,329	89,771,985
1978	77,775,667	9,148,399	464,637	279,221	87,667,954
1977	75,923,145	8,943,732	448,009	275,298	85,590,212
1976	74,161,846	8,750,949	427,403	272,935	83,613,161
1975	72,570,187	8,591,108	414,665	268,901	81,844,890
1974	70,949,607	8,472,817	422,736	257,201	80,102,390
1973	69,438,429	8,361,847	413,383	247,546	78,461,251
1972	67,314,000	8,200,033	369,952	266,219	76,150,204
1971	65,650,046	8,002,572	355,967	256,486	74,265,071
1970	64,017,662	7,865,073	352,993	249,250	72,484,978
1969	62,598,910	7,744,851	348,648	236,729	70,929,138
1968	61,439,030	7,706,779	333,650	236,554	69,716,013
1967	60,033,404	7,579,626	324,222	230,273	68,167,525
1966	58,826,283	7,536,066	316,098	231,346	66,909,793
1965	57,596,016	7,419,956	309,615	231,833	65,577,520
1964	56,307,195	7,293,997	318,168	229,926	64,148,646
1963	55,073,055	7,232,065	320,732	231,599	62,857,451
1962	53,649,362	6,980,960	441,394	252,201	61,323,917
1961	52,569,050	6,843,592	515,389	202,149	60,130,180
1960	51,446,472	6,759,902	453,582	209,810	56,869,766
1959	50,403,378	6,462,452	443,382	195,549	57,504,761
1958	49,196,034	6,382,192	440,676	189,589	56,208,491
1957	48,265,675	6,291,505	429,954	183,955	55,171,089
1956	47,165,228	6,239,387	412,778	177,500	53,994,893
1955	45,827,590	6,156,273	402,439	172,299	52,558,601
1954	44,552,411	6,132,365	364,188	165,595	51,214,559
1953	43,380,360	6,004,322	352,879	161,504	49,899,065
1952	42,176,984	5,780,824	333,207	159,556	48,450,571
1951	40,656,611	5,678,640	322,190	164,438	46,821,879
1950	38,906,917	5,615,616	305,557	158,204	44,986,294
[3]1949	35,375,366	5,290,768	232,125	148,107	42,850,781
[3]1948	33,549,396	5,131,730	204,230	142,053	40,721,988
[3]1947	31,621,959	4,960,895	191,363	135,597	38,431,950
[3]1946	29,769,107	4,692,850	174,662	122,381	36,140,291
[3]1945	28,116,998	4,398,184	162,338	119,112	34,031,073
[3]1944	27,371,260	4,263,395	151,652	116,801	33,048,392
[3]1943	26,872,639	4,168,245	146,593	118,976	32,396,300
[3]1942	26,620,456	4,219,457	149,928	123,711	32,210,440
[3]1941	26,025,513	4,299,976	172,(77	122,486	31,607,371
[3]1940	24,951,906	4,260,255	177,905	115,123	30,191,001
[3]1939	23,965,035	4,215,254	184,299	106,469	29,105,306
[3]1938	23,111,762	4,127,357	191,722	106,631	28,063,710
[3]1937	22,372,385	4,071,633	197,262	102,157	27,262,319
1936	20,987,440	3,825,289	280,024	70,202	26,205,879
1935	20,446,436	3,710,771	304,592	62,208	25,312,802
1934	19,866,008	3,670,419	323,527	58,920	24,662,828
1933	19,300,834	3,620,812	334,612	57,337	24,027,153
1932	19,140,287	3,603,668	370,830	53,507	23,877,741
1931	19,658,018	3,724,013	348,260	60,693	24,489,770

[1]Beginning in 1995, ultimate are not wholly comparable on a year-to-year basis due to changes from one classification to another

[2]Revised

[3]Adjusted to conform to the new system of accounts prescribed by the Federal Power Commission, effective January 1, 1937

Over the last ten years, the number of residential electric customers and commercial customers have been increasing at a comparable rate. The number of residential customers increased at a 1.5% average annual rate and commercial customers at a 2.1% rate. The number of industrial customers decreased at a 0.5% average annual rate. The total number of customers increased at a 1.6% average annual rate.

It should be remembered that consumption per capita has increased steadily throughout the history of the industry, and that consumption for power particularly grew far more rapidly than the mere number of customers would suggest.

Note: Data for 2000 not available

RESIDENTIAL OR DOMESTIC SERVICE

Source: EDISON ELECTRIC INSTITUTE

[4]Year Number of Customers
Dec. 31 —— [5]New Classification —— —— K.w.h. per Customer ($)
Average Annual Bill (¢)
Revenue per K.w.h. Kilowatt-hour Sales ($)
Revenue

1999	125,242,583	1,140,761,000	93,142,367	10,388	848.16	8.16
[5]1998	124,040,512	1,127,735,000	93,166,203,000	10,371	856.81	8.26
1997	107,093,501	1,078,605,000,000	90,881,203,000	10,072	848.62	8.43
1996	105,334,712	1,082,358,000,000	90,465,389,000	10,275	858.84	8.36
1995	103,804,131	1,042,399,000,000	87,597,523,000	10,042	843.87	8.40
1994	102,729,353	1,008,492,000,000	84,517,317,000	9,868	827.03	8.38
[2]1993	101,307,528	994,144,000,000	82,436,503,000	9,864	817.92	8.29
1992	99,635,244	929,290,000,000	76,392,219,000	9,392	772.10	8.22
1991	98,184,250	948,807,000,000	76,350,757,000	9,719	782.06	8.05
1990	97,033,887	915,799,000,000	71,666,279,000	9,508	744.03	7.83
1989	95,616,026	898,802,000,000	68,760,042,000	9,470	724.50	7.65
1988	93,921,875	886,070,000,000	66,402,539,000	9,498	711.78	7.49
1987	92,399,323	846,457,000,000	63,049,059,000	9,236	687.95	7.45
1986	90,994,586	820,015,000,000	60,910,603,000	9,090	675.17	7.43
1985	89,819,726	792,875,000,000	58,591,751,000	8,906	658.11	7.39
1984	87,938,995	782,608,000,000	56,116,141,000	8,978	643.75	7.17
1983	85,842,195	750,293,000,000	51,226,246,000	8,814	601.77	6.83
1982	84,371,779	732,678,000,000	48,188,127,000	8,743	563.09	6.44
1981	83,304,355	730,479,000,000	42,824,457,000	8,825	517.39	5.86
1980	82,153,162	734,411,000,000	37,580,892,000	9,025	461.81	5.12
1979	79,620,180	695,996,000,000	30,798,693,000	8,843	391.30	4.43
1978	77,775,667	679,156,000,000	27,381,419,000	8,430	363.56	4.03
1977	75,923,145	652,345,000,000	24,687,500,000	8,693	328.60	3.78

1976	74,161,846	613,072,000,000	21,149,590,000	8,360	288.42	3.45
1975	72,570,187	586,149,000,000	18,803,156,000	8,176	262.45	3.21
1974	70,949,607	554,960,000,000	15,702,853,000	7,907	223.77	2.83
1973	69,438,429	554,171,000,000	13,194,773,000	8,079	192.28	2.38
1972	67,314,000	511,423,000,000	11,729,833,000	7,691	176.12	2.29
1971	65,650,046	479,080,000,000	10,483,526,000	7,380	161.62	2.19
1970	64,017,662	447,795,000,000	9,415,707,000	7,066	148.39	2.10
1969	62,598,910	407,922,000,000	8,532,729,000	6,571	137.33	2.09
1968	61,439,030	367,692,000,000	7,802,033,000	6,057	128.41	2.12
1967	60,033,404	331,525,000,000	7,183,908,000	5,577	121.02	2.17
1966	58,826,283	306,572,000,000	6,733,714,000	5,265	115.83	2.20
1965	57,596,016	280,970,000,000	6,328,756,000	4,933	110.99	2.25
1964	56,307,195	262,010,000,000	6,040,681,000	4,703	108.64	2.31
1963	55,073,055	241,692,000,000	5,722,544,000	4,442	105.28	2.37
1962	53,649,362	226,414,000,000	5,457,614,000	4,259	102.64	2.41
1961	52,569,050	209,021,000,000	5,115,799,000	4,019	98.47	2.45
[3]1960	51,446,472	196,400,000,000	4,855,799,000	3,854	95.19	2.47
1959	50,403,378	180,186,000,000	4,514,707,000	3,618	90.81	2.51
1958	49,196,034	164,839,000,000	4,184,033,000	3,389	86.08	2.54
1957	48,265,675	152,592,000,000	3,909,453,000	3,198	81.87	2.56
1956	47,165,228	139,025,000,000	3,621,729,000	2,989	78.01	2.61
1955	45,827,590	125,371,000,000	3,322,837,000	2,773	73.48	2.65
1954	44,552,411	113,065,000,000	3,048,925,000	2,573	69.47	2.74
1953	43,380,360	101,244,000,000	2,777,148,000	2,369	64.91	2.74
1952	42,176,984	90,513,000,000	2,508,374,000	2,186	60.55	2.77
1951	40,656,611	80,510,000,000	2,264,747,000	2,021	56.79	2.81
1950	38,906,917	70,055,000,000	2,020,839,000	1,845	53.14	2.88
1949	35,375,366	58,139,346,000	1,716,532,700	1,684	49.68	2.95
1948	33,549,396	50,978,192,000	1,532,663,300	1,563	47.05	3.01
1947	31,621,959	44,171,314,000	1,366,498,200	1,438	44.43	3.09
1946	29,769,107	38,570,913,000	1,240,576,900	1,329	42.79	3.22
1945	28,116,998	34,183,915,000	1,167,356,000	1,229	41.91	3.41
1944	27,371,260	31,266,439,000	1,097,725,500	1,151	40.40	3.51
1943	26,872,639	28,621,403,000	1,029,259,700	1,070	38.52	3.60
1942	26,620,456	26,936,773,000	990,185,300	1,022	37.51	3.67
1941	26,025,513	25,123,900,000	938,228,600	986	36.78	3.73
1940	24,951,906	23,317,569,000	895,951,400	952	36.56	3.84
1939	23,965,035	21,083,507,000	843,157,600	897	35.88	4.00
1938	23,111,762	19,371,156,000	802,532,100	853	35.31	4.14
1937	22,372,385	17,690,741,000	759,824,200	805	34.62	4.30
[2]1936	21,754,153	15,659,181,000	730,999,300	735	34.30	4.67
[2]1935	21,018,952	13,977,920,000	700,358,300	677	33.92	5.01
[2]1934	20,400,211	12,658,180,000	674,826,500	629	33.51	5.33
[2]1933	19,808,356	11,747,355,000	648,839,000	600	33.12	5.52

[1]Includes no "District Rural Rate" service. [2]Includes Eastern Farms only.
[3]Includes Alaska and Hawaii from 1960 on. [4]1950-1965, revised to allocate "Rural" to other appropriate classes of service. [5]Revised.
Note: The most important single factor which has brought about the recorded increase in average consumption per customer in recent years has been the more extensive use of appliances. Data for 2000 not available

INCOME STATEMENT

[1]Privately Owned Electric Utilities - All Departments

Source: U.S. DEPARTMENT OF ENERGY

(thousands of dollars)

Year	Oper Rev	Oper & Maint Exp	Amort & Deprec	Taxes	Total Oper Revenue Deduct	Oper. Income	Other Income	Gross Income	Int. on Lg. Term Debt	Other Income Deduct	Net Income	Pfd Divs	Com Divs
1938	$2,548,532	$1,177,333	$259,297	$365,584	$1,802,214	$753,776	$66,919	$820,695	$284,985	$48,493	$487,217	$122,684	$294,940
1939	2,647,172	1,191,734	279,797	389,390	1,860,921	793,618	70,179	863,797	277,563	51,466	534,768	123,831	320,145
1940	2,796,603	1,257,394	293,817	448,004	1,999,215	804,888	68,149	873,037	266,607	58,766	547,664	123,428	313,986
1941	3,029,430	1,378,811	313,637	575,041	2,267,489	769,557	66,692	836,249	255,970	53,642	526,637	127,064	310,090
1942	3,216,480	1,461,156	329,438	689,081	2,479,675	743,687	58,514	802,201	248,952	63,371	489,878	128,317	279,227
1943	3,464,429	1,620,017	344,724	747,217	2,711,958	759,360	58,020	817,380	243,910	71,947	501,523	124,312	285,762
1944	3,614,572	1,740,919	360,388	732,704	2,834,011	785,675	56,123	841,798	230,904	104,113	506,781	116,719	280,883
1945	3,681,543	1,780,220	359,479	714,035	2,853,734	832,720	54,338	887,058	210,771	141,833	534,454	112,062	294,961
1946	3,815,135	1,935,858	360,383	694,646	2,990,887	829,073	62,046	891,119	192,010	61,483	637,626	105,161	352,939
1947	4,291,065	2,382,411	376,081	721,746	3,480,238	815,367	67,343	882,710	190,516	49,512	642,682	96,196	397,857
1948	4,830,154	2,825,849	403,073	776,643	4,005,565	829,784	65,757	895,551	211,795	26,945	656,808	98,297	394,849
1949	5,068,689	2,820,721	431,556	865,679	4,117,856	956,017	65,733	1,021,750	242,687	21,804	757,259	103,484	456,365
1950	5,527,537	2,979,500	483,392	1,036,772	4,499,664	1,033,078	68,156	1,101,234	259,705	19,586	821,943	111,120	507,960
1951	6,058,483	3,216,023	525,585	1,261,020	5,002,628	1,059,811	62,475	1,122,286	280,491	27,572	814,223	118,860	532,530
1952	6,549,164	3,449,186	562,448	1,345,144	5,356,778	1,195,467	70,274	1,265,741	312,391	6,256	947,094	128,940	595,895
1953	7,136,337	3,734,426	618,002	1,465,768	5,818,196	1,320,506	48,933	1,369,439	357,308	(18,094)	1,030,225	137,802	642,596
1954	7,587,596	3,862,852	692,292	1,576,379	6,131,523	1,456,928	67,185	1,526,113	399,854	(7,853)	1,134,112	143,836	724,127
1955	8,360,374	4,180,556	766,644	1,796,503	6,743,703	1,619,527	63,114	1,682,641	432,490	6,088	1,244,063	150,587	791,588
1956	9,053,731	4,521,064	844,867	1,943,086	7,309,017	1,747,536	60,696	1,808,232	464,252	11,740	1,332,240	160,471	861,320
1957	9,670,378	4,875,433	906,962	2,039,007	7,821,402	1,851,802	64,231	1,916,033	524,308	(20,824)	1,412,549	167,846	901,285
1958	10,194,819	5,036,026	994,260	2,150,891	8,181,177	2,016,283	57,800	2,074,083	610,137	(54,878)	1,518,824	178,202	955,741
[1]1959	11,128,972	5,404,474	1,093,423	2,411,490	8,909,387	2,222,078	63,628	2,285,706	667,551	(37,681)	1,655,836	186,089	1,031,737
1960	11,919,501	5,777,705	1,181,831	2,564,752	9,524,288	2,397,613	78,667	2,476,280	727,456	(34,244)	1,783,068	192,277	1,115,288
1961	12,604,136	6,048,168	1,283,910	2,711,788	10,043,866	2,562,569	67,159	2,629,728	778,685	(23,743)	1,874,786	200,823	1,175,257
1962	13,468,468	6,420,070	1,384,863	2,830,325	10,635,258	2,835,363	72,665	2,908,028	827,497	27,054	2,053,477	205,117	1,256,812
1963	14,179,968	6,736,199	1,489,174	2,934,175	11,159,548	3,022,567	85,017	3,107,584	859,796	69,435	2,178,353	207,456	1,360,012
1964	14,990,858	7,146,599	1,574,871	3,115,688	11,837,158	3,156,472	120,690	3,277,162	898,930	(15,184)	2,393,416	208,798	1,472,904
1965	15,820,144	7,546,445	1,675,375	3,081,567	12,414,699	3,408,560	97,143	3,505,703	947,539	(10,322)	2,580,688	214,145	1,650,270
1966	16,959,019	8,162,042	1,774,338	3,274,364	13,320,016	3,642,142	100,898	3,743,040	1,033,809	(53,183)	2,749,071	220,175	1,717,891
1967	17,935,317	8,632,250	1,893,938	3,380,273	14,039,469	3,898,963	105,627	4,004,590	1,172,726	(76,438)	2,908,302	245,239	1,821,150
1968	19,405,164	9,398,980	2,033,712	3,710,475	15,299,216	4,109,127	124,185	4,233,312	1,365,098	(127,311)	2,995,525	279,423	1,919,093
1969	21,085,458	10,397,588	2,203,241	3,994,005	16,595,734	4,492,915	135,562	4,628,477	1,613,188	(180,672)	3,195,961	307,843	2,003,751
1970	23,127,940	11,978,222	2,398,779	3,731,343	18,243,153	4,884,788	773,452	5,658,240	1,997,365	253,350	3,407,525	362,370	2,158,899
1971	26,027,238	13,884,544	2,627,698	3,827,454	20,625,236	5,402,002	1,064,976	6,466,978	2,423,817	191,166	3,851,995	493,941	2,331,914
1972	29,482,436	15,879,328	2,896,443	4,608,185	23,383,020	6,099,416	1,259,238	7,358,654	2,817,767	121,396	4,419,491	632,192	2,554,109
1973	33,313,906	18,231,343	3,254,645	4,969,125	26,455,113	6,860,036	1,643,012	8,381,859	3,203,515	49,218	4,985,767	790,413	2,848,972
1974	42,174,621	26,632,684	3,623,875	5,332,365	34,588,798	7,585,760	2,097,125	9,578,421	3,936,273	60,119	5,297,452	954,729	3,057,864
1975	50,744,119	30,895,512	4,091,603	7,299,268	41,698,828	9,045,290	2,207,760	11,253,050	4,583,960	55,027	6,198,264	1,139,172	3,489,471
1976	57,970,344	35,490,912	4,539,803	8,811,372	47,910,392	10,059,952	2,488,961	12,548,913	5,138,263	64,509	7,194,191	1,337,652	4,075,987
1977	67,236,740	42,290,564	4,983,786	9,087,530	56,361,436	10,875,304	2,158,631	13,033,935	5,652,820	85,827	8,009,549	1,479,929	4,637,417
1978	74,688,234	47,651,818	5,509,745	9,794,242	62,954,189	11,734,044	2,516,413	14,250,457	6,240,494	111,110	8,716,708	1,625,040	5,252,651
1979	84,149,499	55,646,614	6,070,413	9,889,419	71,604,071	11,845,406	3,066,999	14,912,405	6,992,946	99,440	9,477,811	1,800,588	5,772,159
1980	100,811,773	68,721,371	6,583,335	11,132,139	86,432,337	13,637,206	3,609,262	17,246,468	8,172,758	140,171	10,675,977	2,046,357	6,700,773
1981	118,206,288	80,678,853	7,341,146	13,140,756	101,161,274	16,259,482	4,357,467	20,616,949	9,805,196	152,235	12,729,961	2,254,848	7,798,354
1982	128,381,894	85,282,689	8,082,215	15,877,019	109,241,923	19,139,971	5,343,915	24,483,886	11,101,808	368,851	15,166,781	2,507,444	9,207,131
1983	135,778,026	86,843,346	8,842,859	18,728,490	114,347,166	21,430,860	6,504,769	27,935,629	12,091,561	431,883	17,665,663	2,776,961	10,510,088
1984	147,893,725	92,833,001	9,815,315	21,294,201	123,938,850	23,954,874	6,824,838	30,779,712	13,098,539	511,138	19,697,274	2,861,543	11,236,151
1985	154,798,856	96,369,949	10,911,573	22,199,354	129,471,315	25,327,541	7,430,451	32,757,992	11,403,301	1,113,547	18,704,916	2,964,300	11,904,429
1986	152,831,710	90,066,596	11,773,121	23,777,070	125,605,659	27,226,051	7,220,138	34,446,183	14,679,350	1,364,673	20,423,561	2,649,832	12,601,016
1987	153,644,845	90,858,745	12,559,308	22,152,794	125,560,389	28,084,456	6,564,855	34,649,311	14,194,903	2,277,193	19,024,731	2,297,668	12,953,664
1988	159,488,265	96,002,822	14,192,218	19,544,622	129,730,357	29,757,908	5,030,110	34,788,018	14,360,663	4,061,121	16,041,707	2,264,453	13,517,681
1989	167,067,596	100,530,772	15,813,567	20,171,513	136,500,226	30,567,370	5,215,554	35,782,924	14,472,102	3,598,068	17,312,761	2,417,239	14,030,562
1990	172,999,954	105,331,554	15,705,977	21,470,608	142,471,369	30,528,585	4,084,637	34,613,222	14,815,559	2,613,589	16,897,166	2,025,157	14,189,677
[5]1991	182,450,728	110,174,878	16,995,982	39,172,229	150,361,969	32,088,758	3,915,963	36,004,721	14,725,810	4,245,217	16,949,664	1,935,213	14,427,570
1992	185,493,458	111,750,039	18,031,895	38,590,059	153,682,429	31,811,029	2,859,377	34,670,406	14,203,575	1,549,793	18,384,444	2,039,449	14,897,608
1993	193,637,843	117,040,178	19,056,612	42,678,131	161,908,147	31,729,696	2,835,284	34,564,980	13,476,875	2,608,466	17,891,198	1,765,286	15,334,377
1994	196,281,500	117,991,932	19,732,878	44,061,737	164,207,153	32,074,346	2,793,350	34,687,696	12,784,021	1,461,325	19,887,586	1,581,940	15,875,659
1995	199,966,979	115,539,047	21,000,887	44,441,099	165,321,023	34,645,955	2,956,318	37,602,273	12,719,617	1,495,620	22,060,655	1,518,904	16,249,715
1996	207,459,078	123,448,839	22,331,639	45,075,681	173,920,492	33,538,586	2,775,047	36,313,633	12,106,109	1,757,990	21,228,180	1,248,409	16,810,054

[1]Annual gross of $1,000,000 or more; based on revised system of accounts, effective January 1, 1961. [2]Include Alaska and Hawaii beginning in 1959 [3]Excluded are five independent power producers juridictional to the Federal Energy Regulatory Commission which were included in the prior year's publication.
Note: Data for 1997-99 not available.

SELECTED BALANCE SHEET ITEMS

[1]Private Utilities - All Departments

(Data cover only those companies operating as private electric utilities on December 31st)

Source: DEPARTMENT OF ENERGY - ENERGY INFORMATION ADMINISTRATION

(thousands of dollars)

Year	Utility Plant	Deprec., Amort. & Depletion	Utility Plant (net)	Current Assets	Other Assets & Debits	Total (Assets) (Liabil.)	Common Stock Issued	Preferred Stock Issued	[2]Other Paid-in Capital	Earned Surplus	Lg.-Tm. Debt	Current Liabil.	Total Deferred Credit
1938	14,048,019	1,629,182	12,418,837	1,083,709	1,966,450	15,468,996	4,283,686	2,092,231	224,195	787,768	7,060,333	750,419	270,364
1939	14,114,695	1,762,386	12,352,309	1,041,676	1,923,635	15,317,620	4,327,184	2,059,959	216,057	811,140	6,971,401	655,150	276,729
1940	14,406,987	1,912,974	12,494,013	1,122,902	1,860,235	15,477,150	4,392,601	2,078,219	254,872	860,351	6,895,460	692,038	303,609
1941	14,736,793	2,096,412	12,640,381	1,217,207	1,742,257	15,599,845	4,405,818	2,097,840	265,046	868,210	6,821,692	807,692	333,547
1942	14,848,281	2,306,144	12,542,137	1,364,733	1,704,901	15,611,771	4,351,847	2,135,334	215,390	863,029	6,753,612	908,044	384,515
1943	14,843,649	2,557,241	12,236,408	1,582,936	1,655,338	15,524,682	4,210,241	2,142,825	306,408	845,230	6,587,454	986,599	445,925
1944	14,754,097	2,803,525	11,950,572	1,654,746	1,576,025	15,181,343	4,124,248	2,146,900	279,211	866,463	6,370,785	959,763	433,973
1945	14,490,782	3,044,448	11,446,334	1,672,359	1,333,252	14,451,945	3,879,314	2,071,133	282,266	765,522	6,117,424	964,830	371,456
1946	14,951,566	3,304,548	11,617,018	1,703,936	1,297,689	14,648,643	3,774,156	2,029,840	499,874	833,428	6,129,272	1,003,428	378,645
1947	16,029,031	3,542,034	12,486,997	1,763,374	1,322,879	15,573,250	3,949,270	2,121,717	487,401	888,107	6,581,030	1,203,502	342,223
1948	17,756,583	3,827,765	13,928,818	1,985,206	1,351,780	17,265,804	4,225,670	2,178,701	505,079	1,035,741	7,693,366	1,359,690	267,557
1949	19,627,292	4,046,734	15,580,558	1,898,688	1,426,711	18,905,957	4,623,226	2,392,487	539,874	1,197,125	8,532,128	1,358,533	262,584
1950	21,440,988	4,365,740	17,075,248	2,058,124	1,389,302	20,522,674	5,046,117	2,574,886	589,201	1,345,981	9,178,794	1,527,186	260,509
1951	23,371,575	4,717,515	18,654,060	2,307,468	1,403,518	22,365,046	5,414,410	2,731,382	657,143	1,444,373	9,983,002	1,857,190	277,546
1952	25,729,340	5,092,932	20,636,408	2,442,594	1,423,412	24,502,424	5,866,874	2,896,749	922,475	1,644,712	10,796,531	2,090,417	284,656
1953	28,645,679	5,480,337	23,165,342	2,377,149	1,072,974	26,615,465	6,229,977	3,084,186	863,799	1,867,798	12,030,215	2,227,792	311,698
1954	31,247,271	5,888,482	25,358,789	2,436,859	1,178,891	28,974,531	6,643,746	3,280,741	966,595	2,050,654	13,312,854	2,254,336	465,613
1955	33,708,941	6,390,827	27,318,114	2,567,267	1,107,022	30,992,403	6,942,293	3,461,663	1,083,101	2,191,210	14,315,901	2,380,995	617,240
1956	36,446,185	6,946,259	29,499,926	2,617,581	1,124,266	33,241,773	7,247,731	3,686,547	1,193,373	2,413,984	15,210,750	2,627,411	861,977
1957	39,991,404	7,555,391	32,436,013	2,799,061	1,166,229	36,401,303	7,660,172	3,774,176	1,322,203	2,718,389	17,036,762	2,803,583	1,086,018
1958	43,485,176	8,192,060	35,293,116	2,772,737	1,212,134	39,277,987	8,050,553	4,023,141	1,483,065	3,042,372	18,558,347	2,781,491	1,339,018
1959	46,852,548	8,963,471	37,889,077	2,943,498	1,273,195	42,105,770	8,520,182	4,115,496	1,728,656	3,356,304	19,817,978	2,965,698	1,601,456
1960	50,307,826	9,851,490	40,456,336	3,065,696	1,220,253	44,742,285	9,041,813	4,280,476	1,747,178	3,736,012	21,034,917	3,112,223	1,789,666
1961	53,240,952	10,692,317	42,548,635	3,151,609	1,308,871	47,009,115	9,451,633	4,349,398	1,903,313	4,011,250	22,028,356	3,285,726	1,979,439
1962	56,158,108	11,671,837	44,486,271	3,319,560	1,385,506	49,191,337	9,826,810	4,497,951	1,990,496	4,480,503	22,912,188	3,284,823	2,198,566
1963	59,287,849	12,721,538	46,566,311	3,410,941	1,411,634	51,388,886	10,560,311	4,513,901	1,989,653	4,640,145	23,631,832	3,618,613	2,434,431
1964	62,516,011	13,872,146	48,643,865	3,634,077	1,475,445	53,753,387	11,063,584	4,557,330	2,147,666	5,142,118	24,588,965	3,736,234	2,517,490
1965	66,315,417	15,048,326	51,267,091	3,639,149	1,488,876	56,395,116	10,968,283	4,700,185	2,622,270	5,712,390	25,502,451	4,221,697	2,667,840
1966	71,116,806	16,325,875	54,790,931	4,019,549	1,548,878	60,395,382	11,171,350	5,040,550	2,706,489	6,406,684	29,728,493	4,495,117	2,809,601
1967	77,106,474	17,685,465	59,421,009	4,156,493	1,619,153	65,196,655	11,574,204	5,505,326	2,826,494	6,997,249	30,358,468	4,943,201	2,991,713
1968	83,940,215	19,039,710	64,900,505	4,439,030	1,759,951	71,099,486	11,763,785	5,981,795	3,259,856	7,742,233	33,519,443	5,646,150	3,186,224
1969	92,048,623	20,599,370	71,449,253	4,810,111	2,057,146	78,316,510	12,210,328	6,382,470	3,686,073	8,608,166	37,071,763	6,948,381	3,418,329
1970	102,377,036	22,348,703	79,928,333	5,321,187	2,167,780	87,417,300	13,282,511	7,499,278	4,400,030	9,362,756	41,937,530	7,308,598	3,626,597
1971	113,835,806	24,274,310	89,561,496	5,886,605	2,725,673	98,173,774	14,652,716	9,266,485	5,421,047	10,129,340	46,707,745	7,917,649	4,078,792
1972	126,878,214	26,308,838	100,569,376	6,935,762	3,095,868	110,601,006	16,034,725	11,428,512	6,769,528	11,294,500	51,553,127	8,751,724	4,768,884
1973	141,638,690	28,846,598	112,792,092	7,704,827	4,352,479	124,849,398	17,746,908	13,089,136	8,424,387	12,396,489	56,673,481	10,962,503	5,539,732
1974	157,287,609	31,734,744	125,552,865	11,873,229	5,564,147	142,990,241	19,125,512	14,857,992	9,418,737	13,784,383	64,498,974	15,240,410	6,064,233
1975	172,384,203	34,998,390	137,385,813	13,529,597	6,189,079	157,104,489	20,976,197	16,796,696	11,530,649	15,269,592	70,819,753	13,655,098	8,056,504
1976	189,662,917	38,934,784	150,728,133	15,570,813	6,780,689	173,079,635	23,317,038	18,295,367	13,442,465	16,900,766	76,210,323	14,054,204	10,858,472
1977	209,434,456	43,476,852	165,957,604	18,181,630	7,915,499	192,054,733	25,704,367	19,894,396	15,612,716	18,624,250	82,177,791	16,035,386	14,005,827
1978	231,183,096	48,414,593	182,768,503	18,918,623	9,406,282	211,093,408	27,782,879	21,365,486	17,899,334	20,319,754	88,262,073	18,316,724	17,147,158
1979	256,181,056	53,916,638	202,264,418	22,424,513	10,145,193	234,834,124	30,227,480	23,555,514	20,318,916	22,028,635	95,664,383	23,398,152	20,607,818
1980	281,714,760	59,977,645	221,737,115	26,185,790	12,038,672	259,961,577	33,822,263	25,439,547	22,646,097	23,770,851	105,257,048	26,297,765	23,923,304
1981	308,434,154	66,394,442	242,039,712	28,714,754	15,211,306	285,965,772	37,291,560	26,570,933	23,895,046	26,258,276	115,452,616	28,375,115	28,122,227
1982	338,719,812	73,173,043	265,546,768	31,788,222	18,387,273	315,722,263	42,067,560	28,344,255	27,648,880	29,614,056	124,228,982	28,698,695	35,119,836
1983	365,362,570	80,041,206	285,321,364	33,260,297	23,757,902	342,222,967	46,065,569	29,780,211	31,007,424	33,616,267	131,566,833	29,438,672	40,153,983
1984	395,285,747	87,970,309	307,315,438	37,857,534	30,220,411	375,289,183	48,704,217	30,298,021	33,290,150	39,023,673	140,576,759	31,969,730	47,057,798
1985	431,141,526	97,359,961	333,781,562	39,429,394	31,504,907	404,715,863	52,785,933	30,020,101	35,546,750	43,227,844	152,661,482	31,984,677	53,665,650
1986	455,918,023	107,708,690	348,209,333	38,361,365	39,530,975	426,101,673	53,218,928	28,370,110	37,641,762	48,436,810	157,213,706	34,001,972	61,986,603
1987	475,709,754	118,726,760	356,982,995	40,857,341	48,430,541	446,270,877	53,091,899	26,761,357	39,571,058	50,647,133	158,421,392	39,344,892	71,521,446
1988	492,960,318	131,322,062	361,638,256	39,122,286	53,536,347	454,296,889	54,300,924	26,371,225	39,709,666	49,557,124	160,726,686	38,412,073	78,359,191
1989	507,860,573	144,637,179	363,223,394	41,516,163	60,983,380	465,722,937	56,973,021	25,944,650	38,451,717	50,573,146	162,948,440	42,023,659	81,827,192
1990	528,701,074	157,391,010	371,310,064	41,534,662	65,026,303	477,871,029	57,572,561	25,621,039	39,819,721	50,921,575	167,938,084	44,283,442	85,379,510
[3]1991	548,429,513	171,657,810	376,771,703	43,357,785	67,410,335	487,539,823	58,385,073	25,262,285	42,211,753	51,948,134	171,894,816	43,357,436	88,422,789
1992	571,949,932	185,085,193	386,864,738	43,447,871	76,039,852	506,352,461	60,558,037	25,539,216	43,968,179	52,382,953	174,140,896	45,557,601	96,140,215
1993	593,617,651	199,788,408	393,829,243	42,409,989	130,402,050	566,641,282	61,819,455	25,304,294	46,003,219	52,826,059	174,854,082	48,878,97[illegible]	115,828,731
1994	610,681,388	212,869,134	397,812,254	41,262,977	135,436,442	574,511,673	62,388,946	24,859,833	49,680,940	54,960,728	175,382,079	48,035,056	148,299,243
1995	626,673,964	229,290,816	397,383,148	44,139,661	137,410,904	578,933,714	62,389,082	21,569,103	50,836,690	59,195,307	173,708,479	49,929,403	148,877,493
1996	643,524,892	247,087,068	396,437,823	43,515,064	142,038,077	581,990,963	61,918,621	18,830,248	52,565,379	61,692,140	172,627,107	49,341,620	151,557,174

[1]Annual gross of $1,000,000 or more; based on revised system accounts, effective Jan. 1, 1961. [2]Includes premium on capital stock, capital stock discount and expense, and reacquired capital stock
[3]Excluded are five independent power producers jurisdictional to the Federal Energy Regulatory Commission which were included in the prior year's publication.
Note: Data for 1997-99 not available

INCOME ACCOUNT RATIOS

Years ended Dec. 31

	1996	1995	1994	1993	1992	[1]1991	1990	1989	1988	1987	1986	1985	1984	1983	1982
Elec. oper. rev. percent of total oper. rev.	91.1	91.8	91.4	91.1	91.4	91.4	90.9	90.3	90.2	90.2	89.2	87.4	86.7	85.9	85.9
Percent of oper. revs.															
Operating expenses	57.8	56.4	58.6	58.8	58.7	58.7	59.0	58.1	58.1	57.0	56.3	59.3	59.6	60.5	63.3
Deprec. & amortization	11.2	10.8	10.4	10.3	10.1	9.7	9.5	10.0	9.4	8.6	8.2	7.6	7.2	7.2	6.9
Taxes	N.A.	13.3	14.0	14.3	14.0	13.9	12.9	13.3	13.2	15.0	15.3	14.9	13.5	13.5	12.4
Total oper. rev. deductions	83.1	82.0	82.9	82.9	82.0	81.5	81.3	80.5	80.1	80.5	80.9	82.2	82.3	82.5	83.5
Operating income	16.9	18.0	17.1	17.1	18.0	18.5	18.7	19.5	19.9	19.5	19.1	17.8	17.7	17.5	16.5
Total deprec. exp. % of total utility plant	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	2.6	2.6	2.5	2.5	2.4	2.0
Total utility oper. inc. % net util. plnt. invest	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
Interest on long-term debt															
Percent of operating revenues	5.8	6.4	6.5	7.0	7.7	8.1	8.6	8.7	9.0	9.2	9.6	9.3	8.9	8.8	8.6
Average interest rate	7.0	7.3	7.3	7.7	8.2	8.7	9.0	8.9	9.0	9.0	9.5	9.8	9.6	9.4	9.3
Times earned	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	2.5	2.5	2.4
Net income percent of oper. rev.	10.2	11.0	10.1	9.2	9.9	9.3	9.8	10.4	10.1	12.4	13.4	12.1	13.3	13.0	12.8
Div. appropriated on preferred stock															
Percent of oper. revenues	0.6	0.8	0.8	0.9	1.1	1.1	1.2	1.4	1.4	1.5	1.7	1.9	1.9	2.0	2.0
Average dividend rate	6.2	6.5	6.3	6.9	8.1	7.6	7.9	9.2	8.5	8.3	9.1	9.8	9.5	9.6	9.1
Times earned	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	6.9	7.4	6.0
Div. appropriations on com. stock															
Percent of oper. revenues	8.1	8.1	8.1	7.9	8.0	7.9	8.2	8.4	8.5	8.4	8.2	7.7	7.6	7.7	7.2
Percent of income available for com. stock	84.1	79.1	86.7	95.1	91.1	96.2	95.4	94.2	98.1	77.4	70.9	75.6	66.7	70.6	72.7
Percent of common equity															
Earnings available for common stock	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	11.9	13.1	12.5	14.5	14.2	13.6
Dividend approp. on common stock	9.7	9.7	9.8	9.7	9.7	9.6	9.7	9.7	9.5	9.2	9.3	9.4	9.7	10.0	10.0

[1]Excluded are five independent power producers jurisdictional to the Federal Energy Regulatory Commission which were included in the prior year's publication.
Note: Above based on U.S. Department of Energy tabulation of Income Account for Privately Owned Electric Utilities
Data for 1997-99 not available

BALANCE SHEET RATIOS

Years ended Dec. 31

Relationship	1996	1995	1994	1993	1992	[1]1991	1990	1989	1988	1987	1986	1985	1984	1983	1982
Utility plant per dollar of revenue	3.19	3.20	3.19	3.16	3.18	3.10	3.18	3.19	3.25	3.27	3.19	3.04	2.94	2.98	2.64
Current assets/current liabilities	.88	.88	.86	.87	.95	1.00	.94	.99	1.02	1.04	1.13	1.23	1.18	1.13	1.11
% of total cap. stock, long-term debt & surplus:															
Common stock in other paid-in capital	30.8	30.4	30.0	29.8	29.2	28.6	28.3	28.3	28.5	28.1	27.9	28.1	28.1	28.3	28.3
Preferred stock	5.0	5.9	6.8	7.0	7.2	7.2	7.5	7.8	8.0	8.2	8.7	9.6	10.4	10.9	11.3
Long-term debt	45.8	47.5	48.1	48.5	48.9	49.3	49.3	48.8	48.7	48.3	48.4	48.6	48.2	48.4	49.3
Earned surplus (retained income)	16.9	16.2	15.1	14.7	14.7	14.9	14.9	15.1	15.0	15.4	14.9	13.8	13.3	12.3	11.8
Long-term debt:															
Percent of gross utilities plant	26.8	27.7	28.7	29.5	30.4	31.3	31.8	32.1	32.6	33.3	34.5	35.4	35.6	36.0	36.7
Percent of net utility plant	43.5	43.7	44.1	44.4	45.0	45.6	45.2	44.9	44.4	44.4	45.1	45.7	45.7	46.1	46.1
Reserve for depreciation % of utility plant	38.4	36.6	34.9	33.7	32.4	31.3	29.5	28.5	26.6	25.0	23.6	22.6	22.3	21.9	21.6

[1]Excluded are five independent power producers juridictional to the Federal Energy Regulatory Commission which were included in the prior year's publication.
Note: Above based on U.S. Department of Energy tabulation of Balance Sheet for Privately Owned Electric Utilities.
Data for 1997-99 not available

PUBLICLY OWNED ELECTRIC UTILITIES, EXCLUSIVE OF FEDERAL PROJECTS[2]

Source: DEPARTMENT OF ENERGY

Composite Income Account

(thousands of dollars)

Electric utility operating income	1997	1996	1995	1994	1993	1992	1991	1990	1989	1988	1987
Operating revenues	13,192,690	13,061,729	12,659,255	12,372,824	11,894,965	12,137,324	12,196,916	11,692,371	10,389,832	10,211,349	9,584,490
Operating and maint. expenses	9,175,329	8,604,276	8,998,518	8,662,452	8,387,906	8,617,563	8,843,730	8,368,898	[1]7,598,395	7,375,443	7,042,815
Depreciation & Amortization	1,582,032	1,926,282	1,452,028	1,357,261	1,259,072	1,225,389	1,190,142	1,053,567	964,623	867,431	795,306
Taxes	360,287	358,519	348,796	313,768	309,727	292,578	291,157	283,009	261,476	240,094	231,963
Total oper. rev. deduct	11,117,649	10,889,078	10,799,342	10,333,482	9,956,705	10,135,530	9,965,029	9,705,474	[1]8,824,494	8,482,968	8,070,084
Electric utility oper. inc.	2,086,158	2,183,101	1,869,768	2,060,038	1,949,831	2,004,409	2,166,568	1,918,612	1,511,484	1,667,153	1,458,904
Other income	791,461	771,020	751,208	553,685	743,582	1,034,581	985,872	1,039,117	[1]1,211,571	1,244,854	1,527,596
Gross income	2,844,537	2,925,617	2,534,372	2,600,535	2,663,413	3,038,990	3,152,440	2,957,729	2,723,055	2,912,007	2,986,500
Income deductions											
Interest on long-term debt	1,919,265	1,969,473	2,004,317	2,050,552	2,118,096	2,304,511	2,466,487	2,357,158	2,230,716	2,136,574	2,067,705
Other income deductions	278,716	245,924	226,683	184,921	187,513	140,259	123,776	190,369	206,267	243,588	326,877
Total income deductions	2,188,631	2,203,350	2,209,873	2,222,486	2,295,284	2,433,848	2,590,263	2,547,528	2,436,983	2,380,162	2,394,582
Net income	647,128	728,302	365,462	445,521	285,013	550,803	616,710	337,382	316,766	140,117	481,691

[1]Revised
Note: Data for 1998-99 not available

Composite Balance Sheet

(thousands of dollars)

Assets and other debits:	1997	1996	1995	1994
Electric Utility Plant				
Electric Utility Plant & Adjust	44,711,008	41,380,619	41,207,616	39,878,835
Const Work in Process	1,462,720	1,683,192	1,997,890	2,151,609
(less)Depr. Amort. and Depletion	16,634,454	15,734,638	14,271,591	13,238,697
[1]**Net Electric Utility Plant**	29,539,274	30,329,174	28,933,916	28,791,747
[1]Nuclear Fuel	1,729,312	1,660,261	1,642,978	1,665,312
(less) Amort of Nucl Fuel	1,282,315	1,179,525	1,148,674	1,131,769
[1]**Net Elec Plant Incl Nucl Fuel**	29,986,241	30,809,911	29,428,220	29,325,290
Other Property & Investments				
Nonutility Property	468,726	569,039	545,089	657,347
(less) Accum Provisions for Depr & Amort	151,689	134,694	122,039	244,609
Invest in Assoc Enterprises	139,286	33,635	25,766	205,455
Invest & Special Funds	6,867,954	6,938,936	7,194,090	7,132,469
Total Other Property & Investments	7,324,277	7,406,918	7,635,582	7,750,663
Current & Accrued Assets				
Cash. Working Funds & Investments	4,882,982	4,849,840	4,416,554	4,849,048
Notes & Other Receivables	573,586	527,427	495,277	382,058
[1]Customer Accts Receivable	1,201,546	1,174,324	1,094,034	1,064,278
(less) Accum Prov for Uncollected Accts	34,249	37,002	33,197	28,882
[1]Fuel Stock & Exp Undistr	165,900	254,745	171,408	165,169
Materials & Supplies	538,372	523,853	509,562	531,680
Other supplies & Misc	12,689	12,938	20,977	
Prepayments	178,929	176,817	124,744	175,591
[1]Accrued Utility Revenues	132,989	132,365	202,994	112,858
Miscellaneous Current & Accrued Assets	680,236	714,233	727,126	768,873
Total Current & Accrued Assets	8,332,978	8,329,539	7,729,779	8,020,871
Deferred Debits				
Unamortized Debt Expenses	984,853	1,025,170	1,055,295	1,060,671
Extraordinary Losses. Study Costs	1,054,866	1,074,768	1,212,071	430,460
Mis Debt. R & D Exp. Unamt Losses	5,939,035	5,909,408	5,776,696	6,006,493
Total Deferred Debits	7,978,754	8,009,346	8,044,062	7,497,624
Total Assets & Other Debits	53,622,250	54,555,713	52,837,643	52,594,448
Proprietary Capital				
Investment of Municipality	549,368	571,258	571,935	530,874
Misc Capital	213,753	258,882	242,757	157,856
Retained Earnings	10,993,876	10,643,276	9,719,864	9,409,387
Total Proprietary Capital	11,756,996	11,473,416	10,534,556	10,098,119
Bonds	33,388,827	34,217,934	34,284,699	35,033,368
Advances from Municipality & Other	2,054,358	2,319,891	2,114,846	2,339,863
Unamort Prem on Long-term Debt	98,521	127,336	27,722	30,340
(less) Unamort Discount on Long-term Debt	1,229,740	1,263,504	1,268,431	1,463,755
Total Long-Term Debt	34,311,965	35,401,656	35,158,837	35,939,818
Other Noncurrent Liabilities				
Accum Operating Prov	183,176	196,784	165,759	139,424
[1]Accum Prov for Rate Refunds	3,769	97,822	101,896	103,912
Total Other Noncurrent Liabilities	186,944	294,605	267,655	246,337
Current and Accrued Liabilities				
Notes Payable	1,229,068	1,201,559	1,168,016	1,083,379
Accounts Payable	1,010,639	1,021,779	953,240	921,880
Payables to Assoc Enterprises	128,588	82,075	92,906	65,579
Customer Deposits	74,886	73,312	66,630	130,946
Taxes Accrued	129,591	126,271	126,054	126,084
Interest Accrued	667,658	679,580	691,984	718,438
Misc Current & Accrued Liabilities	1,146,353	996,406	976,639	915,775
Total Current & Accrued Liabilities	4,386,783	4,181,010	4,075,469	3,925,748
Deferred Credits				
Customer Advances for Const	146,117	145,214	85,418	85,537
Other Deferred Credits	2,632,328	2,609,161	2,493,328	2,094,902
Unamort Gain on Reacqr Debt	201,116	450,650	222,379	203,989
Total Deferred Credits	2,979,561	3,205,025	2,801,125	2,384,428
Total Liabilities and Other Credits	53,622,250	54,555,713	52,837,643	52,594,448

[1]Data reporting initiated in 1992
Note: Beginning in 1989, data for publicly owned utilities was presented with extensive changes from 1988 to 1989. For the first time, electric utility only data were collected; therefore, the 1989 data are not compatible with prior years. Data for 1998-99 not available

Composite Balance Sheet

(thousands of dollars)

Assets and other debits	1988	1987	1986	1984	1983	1982	1981	1980	1979	1978	1977
Electric utility plant	33,890,176	32,009,584	30,216,362	37,435,199	34,550,311	32,015,039	29,162,266	26,399,640	24,034,187	26,039,916	23,311,573
Reserves for depr. and amort	7,591,212	6,631,452	5,973,942	8,027,289	7,228,392	6,418,169	5,194,151	4,707,240	4,358,731	5,083,294	4,755,331
Electric utility plant less res	26,298,964	25,378,132	24,242,420	29,407,910	27,321,851	25,626,870	23,968,115	21,692,399	19,675,456	20,956,622	18,586,242
Other utility plant	2,382,866	2,863,706	2,267,777	2,324,890	2,162,012	4,584,732	1,142,817	3,936,018	3,713,083	4,288,991	1,781,014
Reserves for depr. and amort	881,803	986,622	644,380	877,273	807,918	783,704	700,010	612,433	511,478	614,153	584,920
Other utility plant less res	1,501,063	1,877,084	1,623,397	1,447,117	1,354,129	3,801,027	442,807	3,323,584	3,201,605	3,674,838	1,196,094
Total utility plant	36,273,042	34,873,290	32,484,139	39,760,089	36,712,390	36,629,771	30,305,083	30,335,657	27,747,271	30,328,907	25,122,587
Reserves for depr. and amort	8,473,015	7,618,074	6,618,323	8,905,062	8,036,410	7,201,873	5,894,161	5,319,673	4,870,210	5,697,447	5,340,251
Total utility plant less res	27,800,026	27,255,216	25,865,816	30,855,027	28,675,480	29,427,896	24,410,922	25,015,963	22,877,061	24,631,460	19,782,336
Investment & fund accounts	5,278,299	5,390,653	4,914,230	4,904,861	3,525,688	3,518,558	3,033,540	2,926,650	3,001,518	3,388,402	2,442,339
Current & accrued assets	7,977,757	7,979,111	7,788,431	7,522,165	6,664,630	6,456,280	5,431,366	4,592,701	4,210,741	4,365,168	3,674,513
Deferred debits	3,040,615	2,619,857	2,085,937	964,037	900,416	1,916,830	1,844,097	574,256	720,460	465,270	361,582
Total assets and other debits	44,096,698	43,244,836	40,654,415	44,246,093	39,766,214	41,319,566	37,719,925	33,109,592	30,839,770	32,850,600	26,261,170
Liabilities and other credits											
Investment of municipality	499,869	467,458	530,272	545,414	581,433	705,678	587,843	518,684	419,233	710,833	533,846
Surplus	8,737,358	8,885,640	6,689,430	12,391,019	10,875,129	10,155,362	8,240,258	7,491,745	7,034,886	7,762,197	6,755,912
Total investment & surplus	9,237,227	9,353,098	7,219,708	12,936,433	11,456,562	10,861,040	8,828,101	8,010,429	7,454,119	8,473,030	7,289,757
Long term debt	30,201,394	29,981,123	29,392,239	26,873,479	24,632,187	26,799,179	24,003,417	21,043,732	20,108,841	20,910,971	16,027,147
Current & accrued liabilities	2,888,426	2,493,635	2,719,474	3,132,367	2,622,963	2,717,557	2,549,390	2,040,872	1,674,393	2,049,309	1,719,524
Deferred credits	1,501,318	1,231,077	972,667	754,978	705,127	600,831	412,847	532,685	217,791	258,062	190,365
Res. (except res. deduc. contra)	268,304	265,903	250,327	548,836	349,905	330,659	1,926,170	1,478,883	1,321,626	1,169,228	1,034,377
Total liab. & other credit	44,096,698	43,244,836	40,654,415	44,246,093	39,766,214	41,319,566	37,719,925	33,109,592	30,839,770	32,850,600	26,261,170

Note: The data presented are from annual reports of the utilities filed with the Department of Energy. It should be noted that term "publicly owned" as used does not include cooperatively owned utilities.
Data for 1985 not available

INVESTOR OWNED ELECTRIC UTILITIES

Income Statement

Source: ELECTRICAL WORLD

(Millions of dollars)

Year Operating Revenue Operating Expenses Depreci-ation Taxes Total Operating Electric Other Income Gross Corp. Income Amorti-zation & other Deductions Extra-ordinary Income Net Income
Operating Revenue Deductions

1988	135,223	73,324	14,213	19,342	106,879	28,344	4,710	33,114	14,429	dr2,757	15,862
1987	129,619	68,692	12,781	20,900	102,373	27,245	5,749	32,994	13,648	dr2,017	17,282
1986	127,552	67,663	11,165	22,534	101,362	26,190	6,648	34,093	13,554	dr308	20,241
1985	125,547	70,300	10,302	20,748	101,350	24,197	8,779	32,976	12,794	dr1,659	18,524
1984	120,090	67,338	9,106	20,850	97,294	22,796	8,670	31,464	11,771	[1]	19,693
1983	109,446	62,892	8,370	17,523	88,785	20,661	7,807	28,468	10,649	(228)	17,591
1982	101,693	61,243	7,588	14,604	83,435	18,258	6,833	25,091	10,066	121	15,146
1981	94,270	58,842	6,893	12,189	77,924	16,346	5,703	22,050	9,421	28	12,656
1980	80,636	50,457	6,193	10,268	66,600	13,718	4,674	18,392	7,865	2	10,525
1979	68,152	41,380	5,706	9,127	56,213	11,939	3,885	15,824	6,510	(12)	9,302
1978	61,299	35,964	5,172	9,040	50,176	11,123	3,106	14,229	5,621	(34)	8,574
1977	55,142	31,709	4,469	8,424	44,802	10,340	2,645	12,985	5,175	3	7,813
1976	47,080	26,175	4,240	7,221	37,636	9,444	3,105	12,549	5,566	7	6,990
1975	41,855	23,293	3,814	6,212	33,319	8,536	2,666	11,202	5,184	(19)	6,002
1974	34,970	19,542	3,360	4,898	27,800	7,170	3,515	9,685	4,615	76	5,146
1973	27,526	13,512	3,012	4,553	21,077	6,449	1,982	8,431	3,642	62	4,851
1972	24,133	11,666	2,664	4,153	18,483	5,650	1,747	7,397	3,048	7	4,356
1971	21,230	10,155	2,415	3,686	16,256	4,974	1,393	6,367	2,650	57	3,774
1970	18,830	8,695	2,200	3,452	14,347	4,483	[2]	5,603	[2]	[1]	3,333
1969	17,164	7,452	2,009	3,585	13,046	4,118	430	4,548	1,418	[1]	3,130
1968	15,810	6,712	1,857	3,484	12,053	3,757	422	4,179	1,219	[1]	2,960
1967	14,569	6,147	1,727	3,144	11,018	3,551	397	3,948	1,073	[1]	2,875
1966	13,773	5,794	1,580	3,044	10,418	3,355	337	3,692	974	[1]	2,718
1965	12,887	5,382	1,527	2,872	9,781	3,106	348	3,454	898	[1]	2,556
1964	12,211	5,089	1,436	2,803	9,328	2,883	334	3,217	855	[1]	2,362
1963	11,576	4,787	1,360	2,692	8,930	2,737	253	2,990	821	[1]	2,169
1962	10,972	4,560	1,262	2,577	8,399	2,573	279	2,852	776	[1]	2,076
1961	10,301	4,338	1,170	2,451	7,959	2,342	242	2,584	728	[1]	1,856
1960	9,737	4,117	1,087	2,331	7,535	2,202	213	2,415	663	[1]	1,752
1959	9,144	3,916	1,002	2,192	7,110	2,033	183	2,243	617	26	1,626
1958	8,478	3,703	923	1,980	6,607	1,871	163	2,065	550	30	1,515
1957	8,054	3,635	835	1,858	6,331	1,726	145	1,936	509	65	1,427
1956	7,521	3,353	776	1,766	5,895	1,626	139	62	481	1,827	1,346
1955	6,934	3,076	705	1,641	5,422	1,512	121	1,701	443	67	1,257
1954	6,317	2,875	634	1,442	4,946	1,364	107	1,540	389	69	1,151
1953	5,940	2,801	565	1,339	4,705	1,235	98	1,384	343	51	1,041
1952	5,426	2,577	513	1,224	4,314	1,112	92	1,278	322	74	956
1951	5,005	2,400	475	1,150	4,025	980	85	1,134	311	69	823
1950	4,510	2,158	438	948	3,544	966	73	1,113	282	74	831
1949	4,113	2,030	389	794	3,213	900	61	1,032	267	71	765
1948	3,886	2,019	364	712	3,095	791	46	909	243	72	666
1947	3,480	1,701	339	664	2,704	776	51	901	245	74	656
1946	3,127	1,385	324	644	2,348	779	62	909	258	68	651
1945	3,012	1,259	322	652	2,233	779	66	905	360	60	545
1944	2,955	1,225	319	677	2,221	734	63	859	342	62	517
1943	2,816	1,127	307	680	2,114	702	66	834	322	66	512
1942	2,609	1,002	291	628	1,921	688	62	816	317	66	499
1941	2,467	947	279	520	1,746	721	55	849	312	73	537
1940	2,277	863	260	404	1,527	750	62	889	332	77	557
1939	2,148	798	249	352	1,399	749	58	873	334	66	539
1938	2,018	762	226	323	1,311	707	50	820	335	63	485
1937	2,031	781	216	308	1,305	726	51	839	330	62	509
1936	1,911	721	197	281	1,199	712	75	819	359	32	460
1935	1,785	669	184	251	1,104	681	75	790	370	34	420
1934	1,710	635	177	239	1,051	659	70	762	371	33	391
1933	1,640	600	166	212	978	662	80	778	374	36	404
1932	1,713	618	161	201	980	733	85	879	373	61	506
1931	1,874	694	160	195	1,049	825	86	979	388	68	591
1930	1,894	723	156	190	1,069	825	86	979	383	68	596
1929	1,817	709	153	175	1,037	780	85	929	344	64	585

[1]Included in other operating income [2]Due to accounting changes not comparable to previous years
Note: Data for 1989-96 not available

Detail of Operating Expenses

Source: DEPARTMENT OF ENERGY

(Millions of Dollars)

Year Production Transmission & Distribution Cust
Acct. Exp. Sales
Promotion Administra-
tive & General Total Operating Expenses Cost of Fuel Total Salaries & Wages [2]Mainte-nance

1990	70,204	7,321	3,217	212	10,702	92,866	32,635	15,350	330,388
1989	66,553	7,152	2,993	209	9,856	87,723	32,938	14,861	309,592
1988	63,269	6,890	2,894	177	9,537	83,656	31,903	14,257	298,622
1987	59,481	6,645	2,826	142	8,983	78,929	31,474	13,448	291,820
1986	58,219	6,298	2,716	93	8,544	76,692	31,787	12,829	261,308
1985	62,812	6,050	2,524	66	7,920	80,157	36,964	12,187	247,678
1984	60,565	5,623	2,364	17	7,112	76,456	37,792	11,330	221,338
1983	56,020	5,143	2,863	36	6,495	70,542	36,201	10,330	189,209
1982	56,182	4,765	2,624	33	5,959	69,564			
1981	55,323	4,207	2,252	31	5,170	66,982			
1980	46,871	3,791	1,885	28	4,422	56,997			
1979	37,405	3,368	1,637	36	3,796	46,242			
1978	32,294	3,035	1,450	38	3,316	40,163			
1977	28,550	2,727	1,298	43	2,908	35,527			
1976	23,170	2,478	1,193	49	2,520	29,708			
1975	20,503	2,256	968	132	2,221	26,080			
1974	16,866	2,112	829	155	1,930	21,892			
1973	10,577	1,968	692	214	1,682	15,132			
1972	8,738	1,802	612	267	1,491	12,909			
1971	7,465	1,642	555	291	1,305	11,258			
1970	6,144	1,544	502	306	1,163	9,659			
1969	5,114	1,402	449	305	1,034	8,304			
1968	4,520	1,282	418	289	943	7,451			
1967	4,051	1,204	391	274	895	6,815	2,365		
1966	3,159	1,127	378	264	866	5,794	2,210		
1965	2,861	1,076	364	242	839	5,382	1,985		
1964	2,675	1,038	354	226	797	5,090	1,878		829
1963	2,506	975	338	209	759	4,787	1,762		759
1962	2,377	940	321	192	731	4,560	1,671		731
1961	2,273	897	310	176	682	4,338	1,535		682
1960	2,124	885	301	172	635	4,117	1,510		635
1959	2,067	826	281	157	585	3,916	1,425		565
1958	1,967	786	262	133	545	3,703	1,318		544
1957	1,930	789	255	136	528	3,638	1,382		521
1956	1,752	750	240	127	487	3,356	1,236		504
1955	1,580	705	223	116	452	3,076	1,101		468
1954	1,478	686	213	109	434	2,880	989		463
1953	1,454	643	200	101	403	2,801	1,014		432
1952	1,332	535	187	93	370	2,577	919		399
1951	1,264	542	170	86	338	2,400	862		366
1950	1,109	501	158	79	311	2,158	758		340
1949	1,053	469	150	71	287	2,030	706		323
1948	1,100	435	139	69	266	2,019	778		298

1947	879	388	125	64	235	1,701	600	......	261
1946	665	334	111	54	221	1,385	427	550	212
1945	630	289	97	40	203	1,259	383	452	200
1944	641	265	92	35	192	1,225	405	430	186
1943	558	259	92	35	183	1,127	363	412	150
1942	455	247	92	39	169	1,002	283	423	137
1941	416	237	87	50	157	947	250	418	130
1940	344	229	86	52	152	863	203	394	122
1939	302	210	85	51	150	798	170	377	120
1938	263	213	83	53	150	762	148	375	120
1937	290	200	82	60	149	781	165	378	124
1936	250	188	81	56	146	721	155	334	108
1935	217	185	81	47	139	669	125	305	94
1934	200	180	83	39	13	635	116	......	87

[1]Includes such salaries and wages as are applicable to maintenance and to this extent constitutes a duplication of preceding item.
Note: Data for 1991-96 not available.

Source: ELECTRICAL WORLD

Year (in millions) Taxes
%
Oper. Rev. Operating Revenue Taxes

Year	Oper. Rev.	Taxes	%
[r]1988	135,223	19,342	14.3
[r]1987	129,619	20,900	16.1
1986	127,552	22,534	17.6
1985	125,547	20,748	16.5
1984	120,090	20,850	17.4
1983	109,446	17,523	16.0
1982	101,693	14,604	14.4
1981	94,270	12,189	12.9
1980	80,636	10,268	12.7
1979	68,152	9,127	13.4
1978	61,299	9,040	14.7
1977	55,142	8,424	15.3
1976	47,080	7,221	15.3
1975	41,885	6,212	14.8
1974	34,970	4,898	14.0
1973	27,526	4,553	16.5
1972	24,133	4,153	17.2
1971	21,230	3,686	17.4
1970	18,830	3,452	18.3
1969	17,164	3,585	20.9
1968	15,810	3,484	22.0
1967	14,568	3,144	21.6
1966	13,733	3,044	22.1
1965	12,900	2,810	22.2
1964	12,200	2,803	23.0
1963	11,577	2,692	23.3
1962	10,972	2,577	23.5
1961	10,301	2,451	23.8
1960	9,737	2,331	23.9
1959	9,144	2,192	24.0
1958	8,478	1,980	23.4
1957	8,054	1,858	23.1
1956	7,521	1,766	23.5
1955	6,934	1,641	22.7
1954	6,317	1,442	22.8
1953	5,940	1,339	22.5
1952	5,426	1,224	22.6
1951	5,005	1,150	23.0
1950	4,510	948	21.0
1949	4,113	794	19.3
1948	3,886	712	18.3
1947	3,480	664	19.1
1946	3,127	644	20.4
1945	3,012	652	21.7
1944	2,995	677	22.9
1943	2,816	680	24.1
1942	2,611	628	24.1
1941	2,467	520	21.1
1940	2,277	404	17.7
1939	2,148	352	16.4
1938	2,018	323	16.0
1937	2,031	308	15.2
1936	1,911	281	14.7
1935	1,785	251	14.1
1934	1,710	239	14.0
1933	1,640	212	12.9
1932	1,713	201	11.7
1931	1,874	195	10.4
1930	1,894	190	10.0

[r]Revised [p]Preliminary
Note: Including Alaska & Hawaii since 1960.
Data for 1989-96 not available

EMPLOYMENT AND PAYROLLS - ELECTRIC, GAS, AND SANITARY SERVICES

(Revised in accordance with the Bureau of the Budget's 1972 Standard Industrial Classification Manual.)

Source: BUREAU OF LABOR STATISTICS

All Em-ployees
Number (thous.) Average weekly earnings Average weekly hours Average hourly earnings ~ Non-Supervisory Employees ~

Period	Number (thous.)	Average weekly earnings	Average weekly hours	Average hourly earnings
1961	613.7	112.07	40.9	2.74
1962	610.4	116.85	41.0	2.85
1963	610.0	121.54	41.2	2.95
1964	616.5	125.25	41.2	3.04
1965	625.2	131.24	41.4	3.17
1966	631.3	136.95	41.5	3.30
1967	644.0	142.42	41.5	3.44
1968	655.7	150.28	41.4	3.63
1969	671.7	161.41	41.6	3.88
1970	692.3	172.64	41.6	4.15
1971	698.1	185.47	41.4	4.48
1972				
Jan	692.4	193.56	41.5	4.66
Feb	698.2	193.38	41.3	4.68
Mar	700.4	194.30	41.3	4.71
Apr	702.6	196.10	41.3	4.75
May	706.7	197.31	41.3	4.77
June	726.1	197.06	41.2	4.78
July	730.9	202.26	41.8	4.84
Aug	730.9	200.82	41.7	4.82
Sept	719.4	202.54	41.4	4.89
Oct	715.7	206.82	41.9	4.94
Nov	716.9	207.33	41.8	4.96
Dec	718.0	208.05	41.8	4.98
An Av	713.2	200.01	41.5	4.82
1973				
Jan	717.4	208.55	41.9	4.98
Feb	717.2	206.95	41.4	4.99
Mar	720.7	207.04	41.5	4.99
Apr	720.0	209.59	41.5	5.05
May	726.9	211.11	41.6	5.07
June	736.0	214.95	41.9	5.13
July	745.9	216.40	41.9	5.17
Aug	745.8	215.49	42.1	5.12
Sept	734.8	221.52	42.1	5.26
Oct	733.7	221.44	42.2	5.25
Nov	735.1	221.65	42.0	5.28
Dec	737.5	221.80	41.9	5.30
An Av	730.9	214.66	41.8	5.13
1974				
Jan	740.0	222.41	41.8	5.32
Feb	738.7	220.80	41.6	5.31
Mar	739.0	222.28	41.6	5.34
Apr	741.0	227.41	42.0	5.42
May	741.2	225.04	41.5	5.43
June	752.4	226.58	41.5	5.47
July	756.6	231.59	42.0	5.52
Aug	758.0	230.77	41.6	5.55
Sept	742.4	233.41	41.3	5.65
Oct	741.8	234.48	41.3	5.68
Nov	740.9	234.77	41.1	5.72
Dec	738.8	239.80	41.4	5.79
An Av	744.2	229.04	41.5	5.52
1975				
Jan	737.5	240.14	41.3	5.82
Feb	734.2	241.21	41.3	5.84
Mar	729.8	239.55	40.8	5.87
Apr	732.7	241.28	41.0	5.88
May	728.7	242.25	40.7	5.96
June	740.3	245.71	41.1	5.98
July	742.0	246.07	40.9	6.02
Aug	735.9	252.44	41.5	6.08
Sept	726.7	253.07	41.1	6.17
Oct	727.1	255.44	41.2	6.20
Nov	729.0	259.35	41.4	6.27
Dec	727.9	258.68	41.3	6.26
An Av	732.6	247.79	41.1	6.03
1976				
Jan	728.4	261.35	41.3	6.33
Feb	727.5	262.81	41.2	6.38
Mar	728.7	266.66	41.2	6.47
Apr	730.0	265.39	41.2	6.44
May	730.9	266.90	41.0	6.51
June	742.3	269.54	41.2	6.54
July	743.1	271.75	41.1	6.61
Aug	742.4	274.51	41.3	6.64
Sep	733.1	276.80	41.3	6.70
Oct	735.8	279.33	41.4	6.75
Nov	735.5	281.36	41.3	6.81
Dec	736.9	279.70	41.1	6.81
An Av	734.5	271.38	41.2	6.58
1977				
Jan	736.7	283.85	41.2	6.89
Feb	736.0	288.57	41.3	6.98
Mar	734.4	283.71	41.0	6.91
Apr	736.3	286.56	41.0	6.99
May	741.4	289.57	41.2	7.03
June	755.1	287.28	41.1	6.98
July	759.8	295.24	41.5	7.12
Aug	757.7	293.18	41.2	7.12
Sep	749.8	298.29	41.2	7.24
Oct	748.9	302.11	41.3	7.31
Nov	754.2	305.39	41.7	7.33
Dec	756.3	308.77	42.0	7.35
An Av	747.2	293.51	41.3	7.11
1978				
Jan	754.9	315.67	42.1	7.51
Feb	761.1	312.83	41.8	7.48
Mar	765.3	310.55	41.7	7.44
Apr	769.7	313.29	41.7	7.51
May	774.5	313.53	41.6	7.54
June	789.6	318.50	42.1	7.56
July	793.9	318.69	41.6	7.66
Aug	793.6	318.75	41.6	7.66
Sep	782.9	325.20	41.8	7.78
Oct	783.9	327.10	41.7	7.85
Nov	785.2	330.42	41.8	7.90
Dec	785.9	332.30	42.0	7.91
An Av	778.4	319.78	41.8	7.65
1979				
Jan	786.9	338.54	42.2	8.03
Feb	789.6	357.60	41.6	8.59
Mar	793.4	331.32	41.4	8.00
Apr	797.7	336.25	41.4	8.12
May	801.2	336.83	41.4	8.13
June	818.8	342.28	41.9	8.17
July	824.7	340.77	41.3	8.25
Aug	824.4	342.00	41.6	8.23
Sept	815.1	353.57	41.7	8.49
Oct	812.8	353.66	41.8	8.47
Nov	812.4	359.87	42.1	8.55
Dec	812.0	357.22	41.8	8.54
An Av	807.4	343.99	41.7	8.25
1980				
Jan	811.1	357.54	41.7	8.57
Feb	812.6	357.60	41.6	8.59
Mar	816.3	358.21	41.5	8.64
Apr	818.8	361.06	41.5	8.69
May	826.4	365.21	41.7	8.76
June	836.2	366.24	41.7	8.79
July	843.4	379.15	42.3	8.96
Aug.	843.9	375.51	41.8	8.99
Sept.	835.1	378.84	41.6	9.11
Oct.	834.9	382.26	41.7	9.17
Nov.	834.8	387.89	41.8	9.28
Dec.	835.8	385.28	41.5	9.28
An. Av	829.1	371.30	41.7	8.90
1981				
Jan.	833.8	391.76	41.5	9.44
Feb.	834.1	397.16	41.5	9.57
Mar.	837.0	398.27	41.4	9.62
Apr.	840.3	403.10	41.6	9.69
May	847.0	406.43	41.6	9.77
June	863.2	406.13	41.4	9.81
July	871.9	408.20	41.4	9.86
Aug.	871.9	409.77	41.0	9.97
Sept	862.7	416.72	41.3	10.09
Oct	861.7	422.28	41.4	10.20
Nov	863.0	429.11	41.5	10.34
Dec.	863.7	423.95	41.2	10.29
An. Av.	854.2	409.45	41.4	9.89
1982				
Jan.	862.7	443.31	42.1	10.53
Feb.	863.4	438.05	41.6	10.53
Mar.	866.6	433.65	41.3	10.50
Apr	868.0	439.07	41.5	10.58
May	871.0	438.54	41.1	10.67
June	887.3	440.91	41.4	10.65
July	892.7	444.22	41.4	10.73
Aug.	893.6	444.03	41.0	10.83
Sept.	882.3	451.41	41.3	10.93
Oct.	879.2	457.88	41.4	11.06
Nov	880.9	464.67	41.6	11.17
Dec	880.4	464.80	41.5	11.20
An. Av.	877.3	446.29	41.4	10.78
1983				
Jan.	879.3	465.56	41.2	11.30
Feb	878.6	464.43	41.1	11.30
Mar	879.0	464.84	41.1	11.31
Apr	880.5	471.03	41.5	11.35
May	882.8	470.09	41.2	11.41
June	894.3	469.99	41.3	11.38
July	882.4	473.62	41.4	11.44
Aug	888.2	476.10	41.4	11.50
Sept	893.0	482.65	41.5	11.63
Oct	891.5	489.22	41.6	11.76
Nov	893.2	492.40	41.8	11.78
Dec	893.3	492.06	41.7	11.80
An. Av	886.3	476.10	41.4	11.50
1984				
Jan	889.2	497.12	41.6	11.95
Feb	888.9	491.10	41.2	11.92
Mar.	889.8	493.99	41.2	11.99
Apr	891.6	498.08	41.3	12.06
May	896.9	498.08	41.3	12.06
June	911.3	501.70	41.6	12.06
July	918.7	503.42	41.4	12.16
Aug	916.5	503.01	41.4	12.15
Sept	905.4	519.99	41.8	12.44
Oct	904.0	517.09	41.5	12.46
Nov	903.2	524.59	41.8	12.55
Dec	904.1	524.59	41.7	12.58
An. Av	901.6	506.30	41.5	12.20

1985				
Jan	902.9	520.81	41.4	12.58
Feb.	901.0	524.12	41.4	12.66
Mar.	902.7	529.15	41.6	12.72
Apr.	905.6	527.49	41.6	12.68
May	910.3	527.05	41.5	12.70
June	925.3	531.68	41.7	12.75
July	932.8	527.88	41.5	12.72
Aug.	932.3	530.84	41.7	12.73
Sept.	921.4	546.84	42.0	13.02
Oct.	920.8	547.72	42.1	13.01
Nov.	920.5	556.25	42.3	13.15
Dec.	920.1	553.08	41.9	13.20
An. Av.	916.3	535.01	41.7	12.83
1986				
Jan	918.2	550.09	41.8	13.16
Feb.	918.0	554.19	41.7	13.29
Mar	915.5	557.11	41.7	13.36
Apr	916.1	553.43	41.8	13.24
May	921.5	554.61	41.7	13.20
June	928.7	555.03	41.7	13.31
July	934.7	556.85	41.9	13.29
Aug	931.4	556.70	41.7	13.35
Sept.	919.1	563.37	41.7	13.51
Oct	917.6	566.81	41.8	13.56
Nov.	918.4	576.77	42.1	13.70
Dec	918.8	569.32	41.8	13.62
An. Av.	921.4	559.70	41.8	13.39
1987				
Jan.	915.2	564.82	41.5	13.61
Feb	913.8	564.57	41.0	13.77
Mar.	915.5	564.16	41.0	13.76
Apr.	918.5	562.38	41.2	13.65
May	922.4	567.18	41.4	13.70
June	932.8	566.48	41.5	13.65
July	937.8	567.31	41.5	13.67
Aug	937.1	569.25	41.4	13.75
Sept	928.7	573.39	41.4	13.85
Oct	925.6	587.30	42.1	13.95
Nov	924.2	591.93	42.1	14.06
Dec	924.6	587.44	41.9	14.02
An. Av	924.7	572.29	41.5	13.79
1988				
Jan	924.2	583.23	41.6	14.02
Feb.	923.7	581.92	41.3	14.09
Mar.	925.3	581.60	40.9	14.22
Apr	926.3	586.64	41.4	14.17
May	929.4	584.44	41.1	14.22
June	941.0	584.74	41.5	14.09
July	944.4	590.47	41.7	14.16
Aug.	943.0	587.47	41.4	14.19
Sept	930.5	596.96	41.6	14.35
Oct	929.0	607.35	41.8	14.53
Nov	928.7	612.16	41.9	14.61
Dec	926.0	611.74	41.9	14.60
An. Av	931.0	592.21	41.5	14.27
1989				
Jan.	922.8	608.19	41.6	14.62
Feb	920.3	610.07	41.7	14.63
Mar	921.6	606.94	41.6	14.59
Apr	925.5	613.84	41.9	14.65
May	935.9	607.99	41.7	14.58
June	919.0	608.39	41.9	14.52
July	952.6	617.61	41.9	14.74
Aug	954.8	607.99	41.7	14.58
Sept	944.8	623.28	42.0	14.84
Oct	942.9	634.50	42.3	15.00
Nov	942.6	631.31	42.2	14.96
Dec	944.2	629.82	42.1	14.96
An. Av	938.1	616.77	41.9	14.72
1990				
Jan.	942.7	621.26	41.5	14.97
Feb.	943.1	624.67	41.7	14.98
Mar	949.0	624.42	41.6	15.01
Apr.	951.7	629.67	41.7	15.10
May	955.6	623.42	41.7	14.95
June	968.0	625.50	41.7	15.00
July	971.5	633.98	41.6	15.24
Aug	971.6	623.90	41.4	15.07
Sept.	960.4	645.26	41.9	15.40
Oct	958.2	646.25	41.4	15.61
Nov	956.8	655.94	41.7	15.73
Dec	957.0	651.87	41.6	15.67
An. Av	957.1	633.57	41.6	15.23
1991				
Jan	955.4	647.08	41.4	15.63
Feb.	953.3	645.19	41.2	15.66
Mar	955.4	648.00	41.3	15.69
Apr	954.9	648.51	41.6	15.59
May	958.9	645.74	41.5	15.56
June	970.4	649.45	41.9	15.50
July	973.2	644.91	41.5	15.54
Aug.	972.8	642.11	41.4	15.51
Sept.	962.6	661.36	41.7	15.86
Oct.	959.7	662.86	41.9	15.82
Nov.	959.7	674.69	42.3	15.95
Dec	957.7	670.74	42.0	15.97
An. Av	961.2	652.70	41.6	15.69
E1992				
Jan	955.8	652.05	41.4	15.75
Feb	952.6	654.12	41.4	15.80
Mar	951.9	660.61	41.6	15.88
Apr	952.1	666.63	41.9	15.91
May	953.8	668.72	41.9	15.96
June	962.9	663.78	41.8	15.88
July	965.2	675.78	42.0	16.09
Aug	962.1	674.59	41.9	16.10
Sept.	952.5	684.97	42.1	16.27
Oct.	949.3	685.02	42.0	16.31
Nov	945.5	702.57	42.4	16.57
Dec	944.1	697.06	42.4	16.44
An. Av	954.0	673.75	41.9	16.08
E1993				
Jan	941.6	681.82	41.6	16.39
Feb	940.3	686.41	41.5	16.54
Mar	940.6	715.68	42.6	16.80
Apr.	940.3	698.86	42.1	16.60
May	944.7	701.79	42.2	16.63
June	955.3	704.23	42.5	16.57
July	957.7	709.75	42.5	16.70
Aug	956.1	703.03	42.3	16.62
Sept	944.4	711.47	42.4	16.78
Oct	941.3	720.38	42.5	16.95
Nov.	936.5	721.65	42.5	16.98
Dec	934.2	716.56	42.4	16.90
An. Av	944.4	706.83	42.3	16.71
E1994				
Jan	931.3	735.30	43.0	17.10
Feb	928.9	741.32	43.0	17.24
Mar	927.7	723.31	42.2	17.14
Apr	927.5	727.58	42.4	17.16
May	929.4	725.84	42.2	17.20
June	935.7	723.34	42.4	17.06
July	936.5	728.83	42.3	17.23
Aug	933.7	713.94	41.8	17.08
Sept	924.5	728.41	42.3	17.22
Oct.	922.3	750.71	42.8	17.54
Nov.	921.7	742.90	42.5	17.48
Dec.	920.8	737.29	42.3	17.43
An. Av.	928.3	730.98	42.4	17.24
1995				
Jan.	915.3	733.38	42.1	17.42
Feb.	911.8	733.38	42.1	17.42
Mar.	910.3	727.25	41.7	17.44
Apr.	911.7	750.19	42.6	17.61
May	914.2	735.00	42.0	17.50
June	921.8	736.81	42.2	17.46
July	922.5	754.81	42.6	17.72
Aug.	920.9	741.52	42.3	17.53
Sept.	913.0	750.48	42.4	17.70
Oct.	912.2	766.98	42.8	17.92
Nov.	908.8	731.06	43.2	18.08
Dec.	907.9	769.36	42.6	18.06
An. Av.	914.2	748.78	42.4	17.66
1996				
Jan.	892.8	755.16	42.0	17.98
Feb.	888.0	767.02	42.4	18.09
Mar.	886.0	762.13	42.2	18.06
Apr.	885.6	762.43	42.1	18.11
May	887.2	759.23	41.9	18.12
June	892.2	760.87	42.2	18.03
July	890.1	755.88	41.9	18.04
Aug.	887.8	760.90	41.9	18.16
Sept.	880.0	788.80	42.5	18.56
Oct.	876.7	783.65	42.2	18.57
Nov.	876.6	801.13	42.5	18.85
Dec.	875.3	791.06	42.1	18.79
An. Av.	884.9	771.42	42.2	18.28
1997				
Jan.	868.3	784.17	41.8	18.76
Feb.	866.9	781.17	41.8	18.76
Mar.	867.5	792.75	41.9	18.92
Apr.	866.5	805.60	42.4	19.00
May	868.1	795.90	42.0	18.95
June	873.3	801.80	42.2	19.00
July	874.0	799.26	42.0	19.03
Aug.	869.0	802.43	42.1	19.06
Sept.	862.6	808.08	42.0	19.24
Oct.	860.6	814.46	42.2	19.30
Nov.	857.3	836.49	42.7	19.59
Dec.	856.5	815.10	41.8	19.50
An. Av.	865.9	803.69	42.1	19.09
1998				
Jan.	855.6	833.16	42.1	19.79
Feb.	854.6	832.02	42.0	19.81
Mar.	855.2	827.11	41.9	19.74
Apr.	853.5	825.76	41.6	19.85
May	856.9	832.97	41.9	19.88
June	860.8	833.87	42.2	19.76
July	862.7	829.62	41.9	19.80
Aug.	858.8	844.31	42.3	19.96
Sept.	851.8	867.13	42.8	20.26
Oct.	848.3	858.82	42.6	20.16
Nov.	849.8	884.30	43.2	20.47
Dec.	850.0	851.68	42.1	20.23
An. Av.	854.7	843.58	42.2	19.99
1999				
Jan.	845.2	879.02	42.9	20.49
Feb.	844.3	867.34	42.6	20.36
Mar.	845.8	867.50	42.4	20.46
Apr.	841.8	869.62	42.4	20.51
May	844.1	872.02	42.6	20.47
June	851.6	859.96	42.3	20.33
July	850.5	876.46	42.3	20.72
EAug	849.3	868.94	42.1	20.64

E Preliminary
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CONSTRUCTION EXPENDITURES, 1923-1988

(Data cover expenditures by electric utility companies, municipal plants and rural cooperatives)

Source: ELECTRICAL WORLD

(thousands of dollars)

Year	Total Expenditures	Production Plant Total	Steam	Hydro & Pumped Storage	Transmission Plant	Distribution Plant	Miscellaneous
1988	26,469,081	11,740,177	N.A.	629,692	2,876,009	8,319,506	2,903,697
1987	26,264,206	13,219,871	N.A.	551,270	2,458,016	7,831,322	2,203,727
1986	30,200,000	18,676,000	N.A.	N.A.	2,017,000	7,299,000	2,065,000
1985	34,164,794	23,397,645	22,925,040	472,605	2,408,655	6,314,039	2,044,455
1984	38,579,000	27,608,000	N.A.	N.A.	3,101,000	6,088,000	1,782,000
1983	40,103,000	29,922,000	N.A.	N.A.	3,200,000	5,381,000	1,601,000
1982	40,216,000	29,836,000	N.A.	N.A.	3,497,000	5,228,000	1,654,000
1981	35,823,000	27,208,975	25,261,887	590,880	3,168,549	4,950,000	1,882,000
1980	35,925,000	25,688,494	24,793,702	894,792	3,279,885	5,306,661	1,650,207
1979	35,254,000	22,673,695	21,954,389	719,306	3,384,000	5,329,000	1,666,000
1978	30,250,000	19,817,109	19,300,119	517,590	2,736,000	4,346,923	1,216,000
1977	27,712,340	19,095,452	18,120,741	974,711	3,106,186	4,522,293	988,409
1976	25,189,000	16,612,000			2,945,000	4,548,000	1,084,000
1975	20,155,000	12,724,000			2,379,000	4,071,000	981,000
1974	20,556,000	12,504,000			2,451,000	4,577,000	1,024,000
1973	18,723,074	10,923,717	10,019,432	904,285	2,449,951	4,434,105	915,301
1972	16,560,951	9,700,241	8,927,605	772,636	2,134,122	3,989,000	777,000
1971	14,721,745	8,522,079	7,751,080	770,999	2,163,509	3,345,920	690,237
1970	19,537,350	6,836,685	6,056,866	779,819	2,108,877	3,080,875	510,913
1969	10,696,207	5,184,570	4,391,476	793,094	2,194,869	2,845,043	471,725
1968	8,810,598	4,011,784	3,378,886	632,898	1,970,448	2,450,516	377,850
1967	7,784,597	3,499,711	2,765,461	724,250	1,614,284	2,347,602	330,000
1966	6,345,891	2,519,279	1,832,079	687,000	1,417,130	2,107,856	301,626
1965	5,281,322	1,952,045	1,375,827	576,218	1,184,967	1,872,064	272,246
1964	4,817,182	1,818,629	1,256,417	562,212	1,055,486	1,690,213	252,854
1963	4,381,985	1,732,471	1,255,323	477,148	842,022	1,575,015	232,477
1962	4,294,485	1,705,031	1,172,649	532,382	798,303	1,597,730	193,421
1961	4,615,505	1,814,012	1,233,897	580,115	913,949	1,673,204	214,340
1960	4,629,438	2,125,296	1,415,318	709,978	769,430	1,554,417	180,305
r1959	4,354,530	2,121,341	1,611,641	509,700	639,787	1,418,465	174,937
1958	4,598,288	2,349,320	1,887,739	461,581	693,885	1,372,335	182,748
1957	4,745,961	2,234,327	1,717,718	516,609	747,312	1,565,677	198,645
1956	3,780,900	1,478,607	1,110,325	368,282	579,758	1,518,289	186,255

1955	3,621,513	1,547,492	1,230,924	316,568	570,566	1,342,653	160,802
1954	3,387,999	1,444,189	1,338,595	105,594	536,135	1,288,059	119,616
1953	3,187,489	1,537,394	1,441,231	96,113	471,303	1,053,304	119,488
1952	2,901,250	1,389,129	1,260,418	128,711	417,427	988,861	105,833
1951	2,683,000	1,120,000	993,000	127,000	352,000	1,086,000	125,000
1950	2,621,000	1,089,000	981,000	108,000	305,000	1,127,000	100,000
1949	2,843,500	1,249,000	1,094,000	155,000	310,000	1,200,000	84,500
1948	2,357,000	905,000	819,000	86,000	300,000	1,075,000	77,000
1947	1,597,500	492,000	451,000	41,000	214,000	819,000	72,500
1946	850,000	212,000	193,000	19,000	115,000	482,000	41,000
1945	443,750	120,750	108,000	12,750	71,000	235,000	17,000
1944	291,275	97,000	80,000	17,000	50,000	135,275	9,000
1943	305,904	156,925	137,060	19,865	44,218	97,709	7,054
1942	522,200	278,000	203,500	24,500	88,000	191,200	15,000
1941	697,900	227,900	218,900	19,000	98,000	315,000	47,000
1940	640,400	207,000	198,350	8,650	79,100	320,500	33,800
1939	506,500	94,460	82,280	12,180	57,790	320,070	34,180
1938	505,200	149,800	133,500	16,300	51,000	272,900	31,500
1937	553,700	126,800	114,030	12,770	78,580	312,020	36,300
1936	372,500	6,760	37,460	9,300	45,090	256,650	24,000
1935	237,100	37,500	24,680	13,120	35,340	146,660	17,300
1934	175,200	21,060	15,360	5,700	34,180	106,760	13,200
1933	164,000	24,700	17,700	7,000	25,500	102,900	10,850
1932	281,200	53,000	40,000	13,000	51,000	157,200	20,000
1931	541,900	160,560	100,240	60,320	90,900	239,440	51,000
1930	871,600	294,000	176,500	117,500	138,300	354,600	84,700
1929	810,700	260,350	185,350	75,000	156,330	320,020	74,000
1928	755,900	239,000	154,000	85,000	177,600	268,400	70,900
1927	779,400	230,270	151,130	79,140	161,800	301,980	85,350
1926	766,400	285,260	189,060	96,200	173,470	214,790	92,880
1925	846,000	281,000	175,000	106,000	173,300	297,700	94,000
1924	908,000	380,000	270,000	110,000	172,000	255,000	101,000
1923	794,000	283,000	209,000	74,000	160,000	263,000	88,000

[1] Includes Alaska and Hawaii in 1959 and subsequent years
Note: Data for 1989-96 not available.
Note: Because construction expenditures made by governmental agencies, except rural cooperatives, are not readily available prior to 1940, the information shown above covers only such construction for electric utility companies, municipal plants and rural cooperatives. In addition to this change in classification the figures shown for the period 1926-1939 have been revised. In these revised figures an attempt has been made to eliminate wherever possible capital expenditures made in some of the earlier years for the purchase of existing properties rather than actual new construction expenditures. No doubt there may be some such capital expenditures included in the data for the period 1922-1925, but there are no means for checking this.

Construction estimates for 1986 are shown in the table immediately following.

PROSPECTIVE CAPITAL EXPENDITURES, 1988

(Power Companies, State Authorities, Municipal Plants, cooperatives and Federal projects)

(by National Electric Reliability Council regions)

Source: ELECTRICAL WORLD

(Thousands of Dollars)

Region	Fuel Stations	Hydro & Pumped Storage	Transmission	Distribution	Miscellaneous	Total Plant
Northeast Power Coordinating Council	837,256	108,134	367,935	855,109	123,043	2,291,477
Mid-Atlantic Area Council	1,414,656	19,189	131,260	840,020	211,895	2,617,020
East Central Area Reliability Coord. Agreement	1,622,990	15,707	285,827	871,659	309,709	3,105,892
Southeastern Electric Reliability Council	3,424,529	214,268	633,910	1,983,036	753,168	7,008,911
Mid-America Interpool Network	694,599	3,918	129,963	585,766	218,366	1,632,612
Southwest Power Pool	345,875	43,342	237,621	496,200	111,756	1,234,794
Electric Reliability Council of Texas	1,669,741	2,251	171,498	502,600	154,906	2,500,996
Mid-Continent Area Reliability Coord. Agreement	429,663	16,679	92,236	224,892	122,639	886,109
Western Systems Coordinating Coun	1,300,868	206,204	825,759	1,960,224	898,215	5,191,270
Alaska & Hawaii	96,486	7,976	42,764	111,786	38,730	299,562
Total U.S.	11,836,663	639,488	2,918,773	8,431,292	2,942,427	26,768,643

Note: Data for 1989-99 not available

NEW CAPABILITY ADDITIONS REPORTED, Mw

Source: ELECTRICAL WORLD Survey.

Added
1985 1986 1987 1988 1989-
1991 Total Additions Now Planned

Conventional Hydro and pumped storage	2,236	486	205	531	2,107	3,329
Fossil Steam	5,525	6,407	2,759	4,492	7,186	20,844
Nuclear Steam	9,099	13,252	7,929	6,401	5,937	33,519
Combusion Turbine	50	300	50	335	1,142	1,827
Total	16,910	20,445	10,943	11,759	16,372	59,519

Note: Data for 1992-99 not available

COST TRENDS OF ELECTRIC LIGHT AND POWER CONSTRUCTION

By Geographic Divisions

(1973 equals 100)

	North Atlantic Division	South Atlantic Division	North Central Division	South Central Division	Plateau Division	Pacific Division
Jul 1, 2000	384	354	378	354	358	382
Jan 1, 2000	370	342	364	339	349	369
Jul 1, 1999	366	337	360	334	345	365
Jan 1, 1999	365	337	358	336	346	366
Jul 1, 1998	362	335	357	334	343	363
Jan 1, 1998	360	335	353	332	341	361
Jul 1, 1997	354	327	349	327	335	355
[1] Jan 1, 1997	351	326	345	326	333	352
Jul 1, 1996	346	320	341	324	331	348
Jan 1, 1996	344	321	340	321	329	348
Jul 1, 1995	341	316	335	318	323	345
Jan 1, 1995	337	315	332	316	321	339
July 1, 1994	330	306	323	308	312	331
Jan 1, 1994	323	301	316	304	308	326
Jul 1, 1993	318	294	309	295	301	320
Jan. 1, 1993	315	293	308	294	301	319
Jul 1, 1992	308	287	301	289	293	309
Jan 1, 1992	302	282	296	287	288	306
July 1, 1991	305	285	299	289	291	309
Jan 1, 1991	299	282	295	286	286	303
July 1, 1990	296	282	294	285	287	302
Jan 1, 1990	290	279	288	282	282	297
July 1, 1989	286	275	284	278	277	293
Jan 1, 1989	280	268	278	274	272	288
July 1, 1988	273	263	274	269	270	282
Jan 1, 1988	260	253	261	257	258	271
July 1, 1987	251	244	253	250	249	262
Jan 1, 1987	249	242	250	249	248	259
July 1, 1986	249	243	250	249	249	260
Jan 1, 1986	246	241	247	249	247	260
July 1, 1985	244	240	245	247	247	258
Jan 1, 1985	243	241	245	249	248	258
July 1, 1984	239	237	241	246	248	259
Jan 1, 1984	233	233	236	243	244	255
July 1, 1983	231	233	236	242	245	254
Jan 1, 1983	226	230	231	239	240	250
July 1, 1982	222	227	229	234	236	247
Jan. 1, 1982	218	222	226	231	232	240
July 1, 1981	209	218	215	222	222	230
Jan 1, 1981	203	210	208	214	216	225
July 1, 1980	193	197	196	203	202	209
Jan 1, 1980	186	191	190	195	197	200

July 1, 1979	178	182	181	187	188	192
Jan 1, 1979	168	174	173	178	179	181
July 1, 1978	161	165	165	169	170	173
Jan 1, 1978	156	161	159	164	166	168
July 1, 1977	154	158	157	162	163	165
Jan 1, 1977	147	152	149	155	155	157
July 1, 1976	145	148	146	151	152	151
Jan 1, 1976	140	144	141	146	145	146
July 1, 1975	138	140	140	142	143	141
Jan 1, 1975	130	133	132	134	133	132
July 1, 1974	119	120	120	122	120	120
Jan 1, 1974	105	105	104	105	105	105
July 1, 1973	100	100	100	100	100	100
Jan 1, 1973	95	96	96	95	96	96
July 1, 1972	93	94	94	93	94	94
Jan 1, 1972	92	91	94	91	92	93
July 1, 1971	87	88	90	88	89	89
Jan 1, 1971	83	84	86	85	85	85
July 1, 1970	80	81	83	83	82	82
Jan 1, 1970	77	79	80	80	80	80
July 1, 1969	74	76	77	77	77	77
Jan 1, 1969	72	73	74	74	74	74
July 1, 1968	71	71	72	73	73	73
Jan 1, 1968	69	70	71	72	72	72
July 1, 1967	68	68	69	70	71	71
Jan 1, 1967	67	67	67	68	68	69
July 1, 1966	66	66	66	67	67	68
Jan 1, 1966	64	65	65	66	66	67
July 1, 1965	64	64	65	65	66	66
Jan 1, 1965	63	63	63	64	65	65
July 1, 1964	62	62	63	63	64	64
Jan 1, 1964	61	62	62	62	63	63
July 1, 1963	60	61	61	61	62	62
Jan 1, 1963	60	60	61	61	63	62
July 1, 1962	60	61	61	61	63	62
Jan 1, 1962	59	60	61	61	62	62
July 1, 1961	59	60	60	61	62	62
Jan 1, 1961	60	61	61	62	63	63

Above tabulation published by courtesy of Whitman, Requardt and Associates, Baltimore, Maryland 21202. Index numbers shown are a composite of over 50 material and labor items included in the Handy Whitman Index service of cost indexes of construction and equipment. (Source: Edison Electric Institute Statistical Yearbook.) Statistics for 7-1-77 through 1-1-81 received directly

ESTIMATED NET GENERATION AND COST PER KILOWATT HOUR BY TYPE OF FOSSIL FUEL CONSUMED

Source: EDISON ELECTRIC INSTITUTE

Year	COAL Cent per Kwhr	COAL % of Net Generation by fuels	OIL Cent per Kwhr	OIL % of Net Generation by fuels	GAS Cent per Kwhr	GAS % of Net Generation by fuels
United States						
1986	1.66	74.5	2.83	5.5	2.32	10.0
1985	1.73	78.1	4.51	5.6	3.43	16.3
1984	1.79	76.6	5.27	6.8	4.17	16.7
1983	1.80	75.7	5.20	8.4	3.81	15.9
1982	1.79	72.9	5.38	8.5	3.71	18.5
1981	1.66	66.9	5.61	12.4	2.94	20.7
1980	1.47	64.9	4.38	14.6	2.31	20.5
1979	1.33	61.8	3.07	18.5	1.82	19.7
1978	1.22	58.4	2.34	23.0	1.48	18.6
1977	1.02	58.9	2.34	22.6	1.31	18.5
1976	92	59.7	2.08	21.4	1.06	18.9
1975	90	58.2	2.09	20.8	78	21.0
1974	71	56.0	1.92	21.8	53	22.2
1973	44	54.8	82	22.2	37	23.0
1972	40	53.4	65	19.8	33	26.8
1971	38	53.9	59	17.2	31	28.9
1970	33	55.3	42	14.9	29	29.8
1969	28	59.0	35	12.2	27	28.8
1968	27	61.8	35	10.0	26	28.2
1967	26	63.4	34	9.6	26	27.0
1966	26	64.7	34	8.5	26	26.8
1965	25	66.3	34	7.6	26	26.1
1964	25	65.1	34	7.3	29	27.6
1963	24	65.5	35	6.8	27	27.7
1962	27	65.4	36	7.1	28	27.5
1961	27	65.7	37	7.2	28	27.1
1960	28	66.2	37	7.4	26	26.4
1959	28	65.5	38	8.2	25	26.3
1958	30	67.4	44	7.9	24	24.7
1957	31	68.6	50	7.9	23	23.5
1956	30	70.0	44	7.5	22	22.5
New England						
1986	2.05	55.3	2.51	43.1	2.36	1.6
1985	2.18	32.4	4.28	58.2	3.47	9.4
1984	2.15	28.0	4.83	65.2	4.50	6.8
1983	2.29	28.1	4.61	58.0	3.91	13.9
1982	2.37	24.3	4.80	72.5	4.68	3.2
1981	2.05	9.4	4.92	88.6	3.59	2.0
1980	1.73	8.8	4.11	89.7	2.96	1.5
1979	1.64	6.3	2.84	91.9	2.45	1.8
1978	1.54	4.3	2.04	95.3		0.4
1977	1.34	5.7	2.17	93.6		0.7
1976	1.30	4.5	1.92	94.8		0.7
1975	1.19	9.5	2.06	90.0		0.5
1974	1.19	10.6	2.01	87.2	1.50	2.2
1973	56	5.4	77	93.7	64	0.9
1972	51	26.3	65	72.5	46	1.2
1971	43	30.7	60	67.6	49	1.7
1970	38	33.7	40	65.5		0.8
1969	38	35.2	33	63.3	36	1.0
1968	37	40.4	33	58.0	35	1.6
1967	37	45.9	34	52.4	36	1.7
1966	37	57.6	36	40.3	36	2.1
1965	37	62.5	37	34.4	36	3.1
1964	37	65.3	38	31.0	37	3.7
1963	38	65.8	39	31.0	38	3.2
1962	40	65.0	41	32.5	39	2.5
1961	41	65.0	43	32.7	42	2.5
1960	42	60.6	41	35.3	40	4.1
1959	44	58.8	42	36.9	40	4.3
1958	48	65.3	49	30.0	47	4.9
1957	52	67.8	60	28.2	54	4.0
1956	49	67.8	53	28.6	49	3.6
Middle Atlantic						
1986	1.62	78.8	2.86	15.8	2.50	5.4
1985	1.72	68.7	4.55	19.7	3.81	11.6
1984	1.75	65.0	5.38	22.5	4.57	12.5
1983	1.72	49.4	5.16	29.3	4.77	20.3
1982	1.82	64.6	5.60	24.5	4.89	11.0
1981	1.82	59.8	5.66	28.8	4.00	11.4
1980	1.51	59.8	4.56	29.4	3.17	10.8
1979	1.38	60.0	3.19	34.4	2.65	5.6
1978	1.33	54.2	2.30	45.7	....	0.1
1977	1.17	55.0	2.38	44.4	....	0.6
1976	1.11	57.7	2.07	41.5	....	0.8
1975	1.09	57.1	2.13	41.6	1.10	1.3
1974	89	52.3	2.16	44.6	1.21	3.1
1973	51	51.7	89	43.8	68	4.5
1972	46	48.3	71	46.8	62	4.9
1971	45	51.5	66	41.1	.51	7.4
1970	41	53.0	47	38.5	.44	8.5
1969	33	58.6	38	32.4	.40	9.0
1968	31	66.6	39	25.4	39	8.0
1967	30	69.6	37	23.3	38	7.1
1966	.27	72.9	34	20.8	38	6.3
1965	28	76.7	35	16.3	.37	7.0
1964	28	76.8	34	14.8	36	8.4
1963	29	75.2	34	15.2	.36	9.6
1962	31	76.2	37	14.9	41	8.9
1961	33	77.7	39	14.2	42	8.1
1960	33	78.0	39	13.5	41	8.5
1959	34	75.7	42	14.4	38	9.9
1958	37	78.5	44	12.4	38	9.1
1957	38	84.9	55	8.6	39	6.5
1956	34	84.6	43	10.5	36	0.6
East North Central						
1986	1.80	98.9	5.89	0.8	4.10	0.3
1985	1.87	99.1	5.94	0.6	4.77	0.1
1984	1.90	98.9	8.97	0.9	7.04	0.3
1983	1.89	98.2	9.09	1.4	6.34	2.4
1982	1.91	97.3	8.51	2.0	5.24	0.7
1981	1.76	95.6	6.64	3.2	3.66	1.2
1980	1.59	93.7	4.95	4.8	3.04	1.5
1979	1.42	91.4	3.42	6.4	2.53	2.2
1978	1.31	89.6	2.81	8.6	2.11	1.8
1977	1.05	92.1	2.73	6.5	1.57	1.4
1976	93	91.8	2.49	5.6	1.46	2.6
1975	89	90.8	1.06	5.8	1.05	3.4
1974	69	89.4	1.91	5.9	81	4.7
1973	44	90.9	88	5.4	62	3.7
1972	40	89.0	76	5.4	54	5.6
1971	37	86.8	72	4.5	46	8.7
1970	32	87.6	67	2.8	39	9.6
1969	27	92.9		0.7	34	6.4
1968	26	95.0		0.5	29	4.5
1967	25	96.0		0.3	27	3.7
1966	25	96.3		0.2	26	3.5
1965	25	96.9			26	3.1
1964	25	95.9			25	4.1
1963	25	95.7			26	4.3
1962	25	95.9			26	4.1
1961	26	96.2		0.1	25	3.7
1960	24	96.2		0.1	26	3.7
1959	27	94.9		0.1	25	5.0
1958	27	95.9		0.2	27	3.9
1957	28	95.3		0.1	26	4.6
1956	27	95.2			24	4.8
West North Central						
1986	1.34	99.0	3.51	0.2	2.68	0.8
1985	1.43	98.4	5.28	0.2	3.03	1.4
1984	1.55	98.0	10.05	0.1	3.89	1.9
1983	1.57	97.3	5.92	0.3	3.74	2.4
1982	1.49	95.0	6.2	0.5	3.17	4.5
1981	1.40	93.5	4.51	0.5	2.51	6.0
1980	1.28	90.4	4.03	0.9	2.04	8.7
1979	1.23	86.0	2.72	3.0	1.61	11.0
1978	1.10	83.2	2.43	5.2	1.34	11.6
1977	89	81.7	2.34	4.6	1.14	13.7
1976	77	79.0	2.01	5.1	82	15.9
1975	68	70.7	1.96	5.6	61	23.7
1974	52	63.8	1.28	2.6	47	33.6
1973	43	60.8	1.00	2.2	39	37.0
1972	40	58.3	84	2.6	35	39.1
1971	37	55.4	86	1.4	32	43.2
1970	33	54.9	75	1.6	29	43.5

1983	11,064	491.8	5.44	149.3	760.8	510.8	22.79	7,636	47.18	147,649	5,344	1,046
1982	10,871	506.4	[illegible] 50	121.5	743.3	501.1	19.65	8,038	44.61	142,911	5,262	1,050
1981	10,626	452.7	[illegible]	116.6	667.2	394.6	18.79	8,055	40.33	149,913	4,155	1,053
1980	10,452	393.9	4.12	90.5	497.9	350.1	14.68	8,113	30.49	145,788	3,688	1,053
1979	10,077	275.6	2.78	63.6	325.4	244.3	10.50	8,256	19.92	145,744	2,577	1,055
1978	10,260	242.1	2.48	61.2	280.0	218.1	9.72	7,942	16.71	145,535	2,309	1,059
1977	10,216	222.7	2.28	50.5	248.0	207.9	8.35	8,274	15.14	145,359	2,197	1,056
1976	10,144	208.1	2.11	61.9	245.2	154.8	9.97	8,051	15.05	146,153	1,639	1,059
1975	10,073	188.0	1.89	52.3	247.7	105.9	8.17	7,811	15.19	146,038	1,124	1,061
1974	10,261	128.4	1.32	[6]42.1	186.3	60.2	6.49	[6]7,712	11.41	145,856	641	1,065
1973	10,105	65.6	.66	[6]39.0	91.7	42.9	5.95	[6]7,619	5.62	146,022	.455	1,061
1972	10,026	49.4	.50	[6]17.4	77.6	37.8	3.92	[6]11,288	4.79	147,022	.400	1,060
1971	10,056	41.9	.42	[6]19.4	61.5	34.8	4.38	[6]11,265	3.79	146,662	.370	1,063
1970	9,924	32.9	.33	[6]15.1	39.0	32.6	2.70	[6]8,979	2.40	146,861	.348	1,066
1969	9,967	32.0	.32	[6]16.3	36.4	31.3	2.90	[6]8,906	2.27	148,025	.336	1,075
1968	9,926	31.1	.31	....	34.0	30.7	......	......	2.16	151,340	.330	1,075
1967	10,102	30.9	.31	....	32.5	30.7	.....	......	2.08	152,056	.330	1,074
1966	10,078	31.7	.32	[6]18.9	32.2	31.6	4.68	12,342	2.07	152,958	.340	1,076
1965	10,120	31.8	.32	[6]26.2	32.6	31.7	....	11,964	2.11	153,629	.341	1,077
1964	10,186	32.0	.33	.....	30.8	32.2	6.28	......	1.98	152,901	.346	1,075
1963	10,438	33.3	.35	[6][illegible]	32.6	[illegible]	3.84	[6]12,009	2.10	153,337	.360	1,074
1962	10,556	34.5	.36	[6]12.9	33.3	34.8	3.10	[6]12,025	2.17	155,450	.378	1,086
1961	10,552	34.4	.36	[6]11.2	32.8	35.0	2.70	[6]12,041	2.11	153,060	.378	1,079
1960	10,710	32.9	.35	[6]8.7	32.2	33.4	2.09	[6]12,041	2.07	153,054	.359	1,077
1959	10,884	32.5	.35	[6]10.1	33.0	32.4	2.58	[6]12,032	2.14	154,262	.349	1,077
1958	11,337	34.2	.39	[6]9.9	40.0	31.8	2.38	[6]12,025	2.54	151,468	.344	1,081
1957	11,296	32.9	.37	[6]14.6	40.6	27.3	3.54	[6]12,029	2.60	151,797	.282	1,080
1956	11,709	29.6	.35	[6]14.4	34.0	26.1	3.47	[6]12,030	2.17	152,115	.294	1,076

[1]Coal includes bituminous and anthracite coal and relatively small amounts of coke, lignite, wood and corn residue. [2]Oil includes fuel oil, crude oil, and small amounts of tar and gasoline. [3]Gas includes natural and manufactured gas and waste gas. [4]Includes bbl. of oil converted to equivalent tons of coal. [5]Includes screenings. [6]Cords and cubic feet of hogged wood converted to pounds and tons. [7]Includes blast furnace gas. [8]Includes Alaska and Hawaii. [10]Revised.
Source: Annual Statistical reports submitted to the E.E.I. by the Electric Power Companies.

SECURITY SALES BY INVESTOR-OWNED ELECTRIC UTILITIES

Source: PUFT, Inc.

(In Thousand Dollars)

	1995	1994	1993	1992	1991	1990	1989	1988	1987	1986	1985
BY TYPE OF SECURITY											
Long-term debt	5,867,904	7,840,104	32,689,410	21,153,070	8,850,873	7,317,759	10,994,212	9,900,882	13,926,382	20,648,150	12,517,237
Preferred stock	610,000	1,119,500	4,053,984	3,058,794	572,850	715,850	720,000	747,500	1,958,000	1,680,000	655,000
Common	722,403	1,149,870	1,646,967	1,647,126	932,276	216,775	771,981	502,713	245,750	539,695	1,650,013
Total financing	7,200,307	10,109,474	38,390,361	25,858,990	10,355,999	8,250,384	12,486,193	11,151,095	16,130,132	22,968,445	14,822,250
BY TYPE OF SALE											
Public											
Long-term debt	5,845,504	6,248,104	31,296,715	20,097,570	8,399,173	7,021,759	8,272,212	9,077,682	13,131,382	20,026,650	12,305,655
Preferred stock	610,000	1,119,500	3,991,984	2,996,294	497,850	680,850	720,000	747,500	1,958,000	1,680,000	655,000
Common stock	722,403	1,149,870	1,646,967	1,647,126	932,276	216,775	771,981	502,713	245,750	639,695	1,490,103
Private											
Long-term debt	22,400	1,592,000	1,392,695	1,055,500	451,700	296,000	2,722,000	823,200	795,000	621,500	211,582
Preferred stock			62,000	62,500	75,000	35,000				.....	.....
Subscription											
Common stock											159,910
BY PURPOSE OF SALE											
New Money											
Long-term debt	3,376,637	5,750,002	8,729,195	9,007,300	4,886,990	5,593,514	8,337,462	6,800,152	8,687,727	9,741,620	9,188,102
Preferred stock	610,000	1,069,500	2,394,680	3,058,794	505,000	660,000	350,000	552,000	1,205,000	985,000	655,000
Common stock	722,403	1,149,870	1,478,736	1,647,126	864,276	216,775	771,981	502,713	245,750	605,945	1,578,763
Total new money	4,709,040	7,969,372	12,602,611	13,713,220	6,656,266	6,470,289	9,459,443	7,854,865	10,138,477	11,332,565	11,421,865
Total refunding	2,491,267	2,140,102	25,787,750	12,145,770	4,099,733	1,780,095	3,026,750	3,296,230	5,991,655	11,635,880	3,399,685
Total financing	7,200,307	10,109,474	38,390,361	25,858,990	10,355,999	8,250,384	12,486,193	11,151,095	16,130,132	14,821,550	10,939,623
BY METHOD OF SALE											
Competitive	765,000	1,705,000	10,787,003	4,845,000	2,415,000	2,005,000	2,380,000	2,742,900	4,285,125	6,102,245	2,040,685
Negotiated	6,412,907	6,749,974	25,651,066	19,359,546	7,384,299	5,919,384	7,384,193	7,584,995	11,050,007	16,244,700	12,410,073
Subscription											159,910
Private sales	22,400	1,592,000	1,454,695	1,118,000	526,700	331,000	2,722,000	823,200	795,000	621,500	211,582
Total financing	7,200,307	10,109,474	38,390,361	25,858,990	10,355,999	8,250,384	12,486,193	11,151,095	16,130,132	22,968,445	14,822,250

THE INVESTOR'S POSITION IN THE ELECTRIC UTILITY COMPANIES

ALL INVESTORS	BONDHOLDERS					PREFERRED STOCKHOLDERS				COMMON STOCKHOLDERS			
	[1]Value of Plant and Equipment (All Depts.)	Oper. Income Return on Plant	Total Long Term Debt	Int. on Lg. Tm. Debt	[2]Aver. Ann. Yield on Bonds	Value of Pfd. Stock	Annual Div.	Paid Out		Value of Common Stock	Annual Div.	Paid Out	
	(Million $)	%	(Million $)		%	(Million $)		%		(Million $)		%	
1985	336,389	25,530	7.59	148,944	14,470	9.72	12.29	30,614	2,877	9.10	51,556	11,817	22.92
1984	395,504	23,972	6.1	140,696	13,110	9.32	14.03	30,308	2,862	9.44	48,722	11,246	23.08
1983	366,296	21,493	5.9	131,866	12,032	9.12	13.31	29,811	2,780	9.33	46,192	10,535	22.81
1982	338,720	19,140	5.7	124,229	11,102	8.93	15.33	28,344	2,507	8.84	42,068	9,207	21.89
1981	308,434	17,045	5.5	115,453	9,805	8.49	15.62	26,571	2,255	8.19	37,292	7,798	20.91
1980	281,715	14,379	5.1	105,257	8,173	7.76	13.15	25,440	2,046	8.04	33,822	6,701	19.8
1979	256,181	12,545	4.9	95,664	6,993	7.31	10.39	23,556	1,801	7.64	30,227	5,772	19.1
1978	231,183	11,734	5.1	88,262	6,240	7.07	9.22	21,365	1,613	7.55	27,783	5,230	18.8
1977	209,434	10,825	5.2	82,178	5,653	6.88	8.58	19,894	1,556	7.82	25,704	4,531	17.6
1976	189,663	10,060	5.3	76,210	5,138	6.74	9.17	18,295	1,338	7.31	23,317	4,015	17.2
1975	172,384	9,045	5.2	70,820	4,584	6.47	9.88	16,797	1,139	6.78	20,976	3,489	16.6
1974	157,288	7,586	4.8	64,490	3,836	5.95	9.27	14,858	955	6.43	19,126	3,058	16.0
1973	141,639	6,860	4.8	56,673	3,203	5.65	7.83	13,089	790	6.04	17,747	2,849	16.2
1972	126,878	6,099	4.8	51,553	2,817	5.46	7.74	11,429	632	5.53	16,015	2,554	15.9
1971	113,836	5,402	4.7	46,708	2,424	5.19	8.13	9,266	494	5.33	14,653	2,332	15.9
1970	102,[illegible]	4,885	4.5	41,938	1,997	4.76	8.68	7,499	362	4.83	13,283	2,15[illegible]	16.3
1969	92,049	4,493	4.9	37,072	1,613	4.35	7.49	6,382	308	4.83	12,201	2,004	16.4
1968	83,940	4,109	4.9	33,519	1,365	4.07	6.49	5,982	279	4.66	11,764	1,919	16.3

1967	77,106	3,899	5.1	30,358	1,173	3.86	5.81	5,505	245	4.45	11,574	1,821	15.7
1966	71,117	3,642	5.1	27,728	1,034	3.73	5.36	5,040	220	4.37	11,171	1,718	15.4
1965	66,315	3,408	5.1	25,502	948	3.72	4.60	4,700	214	4.55	10,968	1,650	15.0
1964	62,516	3,156	5.0	24,588	899	3.66	4.53	4,557	209	4.57	11,063	1,472	13.3
1963	59,288	3,023	5.1	23,632	860	3.64	4.41	4,550	207	4.55	10,100	1,360	13.5
1962	56,158	2,835	5.0	22,912	827	3.61	4.51	4,498	205	4.56	9,827	1,257	12.8
1961	53,241	2,563	4.8	22,028	779	3.54	4.57	4,349	201	4.62	9,452	1,175	12.4
1960	50,308	2,398	4.8	21,035	727	3.45	4.69	4,281	192	4.48	9,042	1,115	12.3
1959	46,853	2,222	4.7	19,818	668	3.37	4.70	4,115	186	4.52	8,520	1,032	12.1
1958	43,485	2,016	4.6	18,558	610	3.29	4.10	4,023	178	4.42	8,051	956	11.9
1957	39,991	1,852	4.6	17,037	524	3.08	4.18	3,774	168	4.45	7,660	901	11.8
1956	36,446	1,748	4.8	15,211	464	3.05	3.54	3,686	160	4.34	7,248	861	11.9
1955	33,709	1,620	4.8	14,316	432	3.02	3.22	3,462	151	4.36	6,942	792	11.4
1954	31,247	1,459	4.7	13,313	400	3.00	3.15	3,281	144	4.39	6,644	724	10.9
1953	28,646	1,321	4.6	12,030	357	2.97	3.45	3,084	138	4.47	6,230	643	10.3
1952	25,729	1,195	4.6	10,797	312	2.89	3.20	2,897	129	4.45	5,867	596	10.2
1951	23,172	1,060	4.5	9,983	280	2.80	3.09	2,731	119	4.36	5,414	533	9.8
1950	21,441	1,033	4.8	9,179	260	2.83	2.82	2,575	119	4.31	5,046	508	10.1
1949	19,627	956	4.9	8,532	243	2.85	2.90	2,392	103	4.31	4,623	456	9.9
1948	17,757	830	4.7	7,693	212	2.76	3.03	2,179	98	4.50	4,226	395	9.3
1947	16,029	815	5.1	6,581	191	2.90	2.78	2,122	96	4.52	3,949	398	10.1
1946	14,952	829	5.5	6,129	192	3.13	2.71	2,030	105	5.17	3,774	353	9.4
1945	14,491	833	5.7	6,117	211	3.45	2.89	2,071	112	5.41	3,879	295	7.6
1944	14,754	786	5.3	6,371	231	3.63	2.97	2,147	117	5.45	4,124	281	6.8
1943	11,181	759	5.2	6,587	244	3.70	2.99	2,143	124	5.79	4,210	286	6.8
1942	14,848	744	5.0	6,754	219	3.69	3.11	2,135	128	6.00	4,352	279	6.4
1941	14,737	770	5.2	6,822	256	3.75	3.11	2,098	127	6.05	4,406	310	7.0
1940	14,407	805	5.6	6,895	267	3.87	3.25	2,078	123	5.92	4,393	324	7.4
1939	14,115	794	5.6	6,971	278	3.99	3.48	2,060	124	6.02	4,327	320	7.4
1938	14,048	754	5.4	7,060	285	4.04	3.87	2,092	123	5.88	4,281	295	6.9

[1]All figures apply to "Class A and B" Companies up to and including the year 1960 and, under the revised Uniform System of Accounts, $1,000,000 or more after 1960. The "Value of Plant and Equipment" includes, besides that devoted to electricity, the value of plant devoted to gas, steam, water, traction, etc., in the so-called "combination companies." The above figures are as stated by the U.S. Department of Energy in their "Statistics of Privately Owned Electric Utilities in the United States", 1979 and "Financial Statistics of Selected Electric Utilities", 1983.
[2]Composite average on public utility bonds as reported by [illegible] Investors Service
[3]Restated to reflect changes made to Schedule [illegible] the [illegible] Statistical Report
Note: Data for 1986-95 not available.

Comparative Data For Independent Electric Operating Companies - 1997

Oper. Revs.
($ Mill.) No. of Shares per share
% — Common Equity
% of Tot. Capital Bal. for Com
% of Oper. Rev. Book Value per Com. Share Net Oper. Inc.
% of Net Plant Div. Payout
% of Net Earn per Sh. Div. Paid Rev. Earn — Growth
(5 yr.)

Revenues In Excess of $1,000,000,000					
Baltimore Gas & Electric Co	3,307.6	19.40	71	1.72	1.22
Carolina Power & Light Co	3,024.1	18.63	71	2.66	1.88
[5]CINergy	4,352.8	16.10	113	1.59	1.80
Citizens Utilities Co.	1,393.6	6.59	.....	0.04	.....
Consolidated Edison, Co. of N.Y.	7,121.3	25.18	.....	2.95	.....
[2]Duke Energy Corp	16,308.9	19.56	86	2.50	2.16
Illinova Corp	2,509.5	20.23	66	1.41	0.93
Niagara Mohawk Power Corp	3,966.4	18.03	...	0.16	.....
Northern States Power Co	2,733.7	13.27	87	1.61	1.40
OGE	1,472.3	12.19	123.5	1.62	2.00
[3]PECO	4,617.9	12.25	125	1.44	1.80
Puget Sound Power & Light Co	1,676.9	16.06		1.28	.....
Unicom Corporation	7,083.0	22.70	...	d1.10	1.60
Utilicorp United, Inc	8,926.3	21.74	78	2.26	1.76
[1]Western Resources, Inc	2,151.8	17.73	28	7.51	2.09
Revenues Between, $600,000,000 and $1,000,000,000					
Central Maine Power Co.	954.2	15.03	562	0.16	0.90
Kansas City Power & Light Co	895.9	14.19	137	1.18	1.62
Montana Power Co	1,023.6	18.48	70	2.28	1.60
Nevada Power Co	799.1	16.56	97	1.65	1.60
Orange & Rockland Utilities Co	648.8	27.69	84	3.09	2.58
Washington Water Power Co	1,302.0	13.38	63	1.96	1.24
WPS Resources Corp	878.3	20	85	2.25	1.92
Revenues Between $500,000,000 and $600,000,000					
Central Hudson Gas & Electric	520.3	27.61	72	2.97	2.13
Idaho Power Co	748.5	18.93		2.32	1.86
Revenues Between $300,000,000 and $500,000,000					
Central Louisiana Electric Co. Inc					
Revenues Between $100,000,000 and $200,000,000					
Green Mountain Power Corp	179.3	21.61	103	1.57	1.61
Holding Companies					
American Electric Power Co. Inc	6,161.4	24.62	73	3.28	2.40
Central & South West Corp	[illegible]	10.03	112	1.55	1.71
Cilcorp, Inc	976.5	25.91	346	0.71	2.46
C.M.S. Energy Corp.	4,787.0	19.59	26	2.61	1.14
Commonwealth Energy Systems	1,041.7	20.01	69	2.27	1.57
DPL, Inc	1,355.8	8.03	76	1.20	0.91
DQE, Inc	1,219.2	19.30	54	2.54	1.36
Eastern Utilities Associates	568.5	54.52		1.86	1.66
[6]Edison International	9,235.0	14.70	57.8	1.73	1.00
Florida Progress Corp	3,315.6	18.30	175	0.56	2.10
FPL Group Inc	6,369.0	26.62	54	1.57	1.92
Hawaiian Electric Industries, Inc	1,464.0	21.70	89	2.45	2.44
Houston Industries Inc	6,873.4	9.69	90	1.66	1.50
New England Electric System	2,502.6	27.03	70	3.39	2.36
Northeast Utilities	3,834.8	16.34		d1.05	0.25
PacifiCorp	6,278.0	12.79	159	0.68	1.08
Public Service Enterprise Group Inc	6,370.0	22.47	90	2.41	2.16
SCANA Corp	1,523.0	16.68	73	2.06	1.50
Sierra Pacific Resources	663.2	20.49	51	2.40	1.23
Southern Co	12,611.0	13.92	92	1.42	1.30
TECO, Energy, Inc	1,862.3	11.04	72	1.61	1.17
Texas Utilities Co	7,945.6	27.90	71	2.85	2.10
TNP Enterprises, Inc	585.2	22.71	15	2.26	1.00

[1]Formerly Kansas Power & Light Co
[2]Stock dividends
[3]Formerly Philadelphia Electric Co
[4]Company started operations in 1993
[5]Formerly Cincinnati Gas & Electric Co
[6]Formerly SCE Corp

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KENTUCKY POWER COMPANY
ELECTRIC UTILITY INDUSTRY COMMON EQUITY RATIOS

ELECTRIC COMPANIES	EQUITY RATIO	COMBINATION GAS & ELECTRIC COMPANIES	EQUITY RATIO
ALLETE, Inc. (NYSE-ALE)	54.9	Alliant Energy Corporation (NYSE-LN'	51.7
American Electric Power Co. (NYSE-AE]	45.2	Ameren Corporation (NYSE-AEE)	52.1
Central Vermont Public Serv. Corp. (NYS	51.9	Avista Corporation (NYSE-AVA)	46.3
Cleco Corporation (NYSE-CNL)	50.4	Black Hills Corporation (NYSE-BKH)	39.8
Edison International (NYSE-EIX)	42.9	CenterPoint Energy (NYSE-CNP)	31.7
El Paso Electric Company (NYSE-EE)	48.4	CH Energy Group, Inc. (NYSE-CHG)	47.7
FirstEnergy Corporation (ASE-FE)	42.4	Chesapeake Utilities Corporation (NYSE	60.8
Great Plains Energy Incorporated (NYSE-	43.5	CMS Energy Corporation (NYSE-CMS)	29.2
Hawaiian Electric Industries, Inc. (NYSE-	48.0	Consolidated Edison, Inc. (NYSE-ED)	51.7
IDACORP, Inc. (NYSE-IDA)	51.8	Constellation Energy Group, Inc. (NYSE	60.4
Nextera Energy (NYSE-NEE)	39.8	Dominion Resources, Inc. (NYSE-D)	37.3
Otter Tail Corporation (NDQ-OTTR)	56.0	DTE Energy Company (NYSE-DTE)	46.4
Pinnacle West Capital Corp. (NYSE-PNV	49.1	Duke Energy Corporation (NYSE-DUK)	54.5
PNM Resources, Inc. (NYSE-PNM)	44.9	Empire District Electric Co. (NYSE-EDI	49.5
Portland General Electric (NYSE-POR)	47.9	Entergy Corporation (NYSE-ETR)	41.5
Progress Energy Inc. (NYSE-PGN)	44.1	Exelon Corporation (NYSE-EXC)	49.6
Southern Company (NYSE-SO)	47.9	Integrys Energy Group (NYSE-TEG)	56.0
Westar Energy, Inc. (NYSE-WR)	44.8	MDU Resources Group, Inc. (NYSE-MI	65.9
		MGE Energy, Inc. (NYSE-MGEE)	60.2
		NiSource Inc. (NYSE-NI)	39.7
		Northeast Utilities (NYSE-NU)	44.4
		Northwestern Corporation (NYSE-NWE	44.2
		NSTAR (NYSE-NST)	44.3
		NV Energy (NYSE-NVE)	40.1
		OGE Energy Corp. (NYSE-OGE)	45.6
		Pepco Holdings, Inc. (NYSE-POM)	47.3
		PG&E Corporation (NYSE-PCG)	48.0
		PPL Corporation (NYSE-PPL)	36.5
		Public Service Enterprise Group (NYSE-	53.7
		SCANA Corporation (NYSE-SCG)	42.3
		SEMPRA Energy (NYSE-SRE)	45.9
INDUSTRY AVERAGE	**46.3**	TECO Energy, Inc. (NYSE-TE)	42.4
INDUSTRY MEDIAN	**45.6**	UGI Corporation (NYSE-UGI)	44.1
		UIL Holdings Corporation (NYSE-UIL)	39.1
		UniSource Energy Corporation (NYSE-l	32.1
		Unitil Corporation (ASE-UTL)	33.7
		Vectren Corporation (NYSE-VVC)	42.9
		Wisconsin Energy Corporation (NYSE-\	43.4
Data from AUS Utility Reports, February 2012, pp. 8, 12.		Xcel Energy Inc. (NYSE-XEL)	45.6

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Exhibit _(SGH-1)
Schedule 1

KENTUCKY POWER COMPANY
RECENT CAPITAL STRUCURES
9/30/10-9/30/11

AMOUNT (000)

Type of Capital	9/30/2010	12/31/2010	3/31/2011	6/30/2011	9/30/2011	AVERAGE
Common Equity	$434,919	$446,216	$458,221	$456,789	$460,487	$451,326
Short-term Debt	$0	$10	$0	$0	$0	$2
Long-term Debt	$548,847	$548,888	$548,930	$548,972	$549,013	$548,930
Total Capital	$983,766	$995,114	$1,007,151	$1,005,761	$1,009,500	$1,000,258

PERCENT

Type of Capital	12/31/2009	12/30/2010	3/31/2011	3/31/2011	3/31/2011	AVERAGE
Common Equity	44.21%	44.84%	45.50%	45.42%	45.62%	45.12%
Short-term Debt	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Long-term Debt	55.79%	55.16%	54.50%	54.58%	54.38%	54.88%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Data from Company response to AG-31.

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KENTUCKY POWER COMPANY
ELECTRIC UTILITY SAMPLE GROUP SELECTION

	Company Name	Revenues % Electric	Pending Merger	Recent Div. Cut?	Generation Assets?	Stable Book Value	Bond Rating S&P	Bond Rating Moody's	Selected
	SCREEN	≥70%	no	no	yes	yes	A- to BBB-		
EAST									
e+g	CH Energy	55	no	no	yes	yes	A	A3	
e	Central Vermont P. S	100	yes	no	yes	yes	NR	Baa1	
e+g	Consolidated Edison	69	no	no	no	yes	A-	A3/Baa1	
e+g	Constellation Energy	17	yes	yes	yes	yes	BBB+	Baa2	
e+g	Dominion Resources	48	no	no	yes	yes	A	Baa1/Baa2	
e+g	Duke Energy	73	yes	no	yes	yes	A-	A2	
e+g	Exelon Corp	50	yes	no	yes	yes	A-	A2/A3	
e	FirstEnergy Corp	75	no	no	yes	yes	BBB	Baa1	√
e	NextEra Energy	72	no	no	yes	yes	A	Aa3	
e+g	Northeast Utilities	86	yes	no	yes	yes	BBB+	A3	
e+g	NSTAR	85	yes	no	no	yes	AA-/A+	A1	
e	PPL Corporation	54	no	no	yes	yes	A-	A3	
e+g	Pepco Holdings, Inc	73	no	no	no	yes	A	A3	
e	Progress Energy	100	yes	no	yes	yes	A/A-	A1/A2	
e+g	Public Service Ent. C	44	no	no	yes	yes	A-	A2	
e+g	SCANA Corp	54	no	no	yes	yes	A-	A3	
e	Southern Company	99	no	no	yes	yes	A	A2/A3	
e+g	TECO Energy	61	no	no	yes	yes	BBB	Baa1	√
e	UIL Holdings Corp	54	no	no	no	yes	NR	Baa2	
CENTRAL									
e	ALLETE	91	no	no	yes	yes	A-	Baa1	√
e+g	Alliant Energy	73	no	no	yes	yes	A-/BBB+	A2/A3	
e+g	Ameren Corp	86	no	yes	yes	yes	BBB-	Baa2	
e	American Eelectric I	93	no	no	yes	yes	BBB	Baa2	√
e+g	CMS Energy Corp	59	no	yes	yes	yes	BBB+	A3	
e+g	CenterPoint Energy	26	no	no	no	yes	BBB+	A3	
e	Cleco Corporation	97	no	no	yes	yes	BBB	Baa2	√
e+g	DTE Energy	58	no	no	yes	yes	A	A2	
e+g	Empire District Elec	91	no	yes	yes	yes	BBB+	A3	
e+g	Entergy Corp	77	no	no	yes	yes	A-/BBB+	Baa1	√
e	Great Plains Energy	100	no	yes	yes	yes	BBB	Baa2	
e+g	ITC Holdings	100	no	no	no	no	A-	A1	
e+g	Intergrys Energy	27	no	no	yes	yes	A-/BBB+	A2/A3	
e+g	MGE Energy	68	no	no	yes	yes	AA-	A1	
e+g	OGE Energy Corp	57	no	no	yes	yes	BBB +	Baa1	
e	Otter Tail Corp	29	no	no	yes	yes	BBB-/BB-	Baa2	
e+g	Vectren Corp	28	no	no	yes	yes	A-	A2	
e	Westar Energy	100	no	no	yes	yes	BBB+	Baa1	√
e+g	Wisconsin Energy	70	no	no	yes	yes	A-	A1	
WEST									
e+g	Avista Corp	64	no	no	yes	yes	A-	Baa1	√
e+g	Black Hills Corp	46	no	no	yes	yes	BBB+	A3	
e	Edison International	82	no	no	yes	yes	BBB+	A1	
e	El Paso Electric	63	no	yes	yes	yes	BBB	Baa2	
e	Hawaiian Electric	91	no	no	yes	yes	BBB-	Baa2	√
e	IDACORP, Inc	100	no	no	yes	yes	A-	A2	
e+g	NV Energy Inc	94	no	yes	yes	yes	BBB	Ba2	
e+g	PG&E Corp	78	no	no	yes	yes	BBB	A3	√
e	PNM Resources	77	no	yes	yes	yes	BBB/BBB	Baa2	
e	Pinnacle West Capit	99	no	no	yes	yes	BBB-	Baa2	√
e	Portland General	99	no	no	yes	yes	A-	A3	√
e+g	Sempra Energy	27	no	no	yes	yes	A+	Aa3	
e	UniSource Energy	84	no	no	yes	yes	BBB+	NR	√
e+g	Xcel Energy, Inc	82	no	no	yes	yes	A	A3	

e= electric company; e+g=combination electric and gas company
Data from Value Line Ratings and Reports, Nov. 25,Dec. 23, 2011 and Feb. 3, 2012; AUS Utility Report:
Avista and TECO selected for sample size and because total regulated revenues equalled 98% and 75% of

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IBES/Thompson
2/16/2011

		MEAN		
		2012 Earnings	5-year Growth	
First Energy Corp.	FE	3.28	0.0185	First Energy Corp.
TECO Energy	TE	1.4	0.0493	TECO Energy
ALLETE	ALE	2.61	0.05	ALLETE
American Electric Pow	AEP	3.3	0.0323	American Electric Pow
Cleco Corporation	CNL	2.45	0.03	Cleco Corporation
Entergy Corp.	ETR	5.83	-0.035	Entergy Corp.
Westar Energy	WR	1.97	0.052	Westar Energy
Avista Corporation	AVA	1.77	0.045	Avista Corporation
Hawaiian Electric	HE	1.67	0.131	Hawaiian Electric
PGE Corporation	PCG	3.21	0.0145	PGE Corporation
Pinnacle West Capital	PNW	3.36	0.0559	Pinnacle West Capital
Portland General	POR	1.93	0.0588	Portland General
UniSource Energy	UNS	2.51	0.03	UniSource Energy
	Average	2.714615385	0.040946	

Zack's			0.047275

2/16/2011

		2012 Earnings	5-year Growth
First Energy Corp.	FE	3.25	0.01
TECO Energy	TE	1.39	0.0467
ALLETE	ALE	2.61	0.05
American Electric Pow	AEP	3.29	0.04
Cleco Corporation	CNL	2.45	n/a
Entergy Corp.	ETR	5.8	0.02
Westar Energy	WR	1.96	0.0609
Avista Corporation	AVA	1.77	0.0467
Hawaiian Electric	HE	1.72	0.0803
PGE Corporation	PCG	3.19	0.0427
Pinnacle West Capital	PNW	3.36	0.0533
Portland General	POR	1.93	0.05
UniSource Energy	UNS	2.48	0.026
	Average	2.707692308	0.044

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FE	Date	Open	High	Low	Close	Volume
	1/27/2012	42.72	42.74	41.8	42.26	10993100
	1/26/2012	42.19	42.99	42.07	42.72	12737000
	1/25/2012	41.04	42.15	40.37	42.13	5385800
	1/24/2012	41.89	41.89	41.2	41.27	2932400
	1/23/2012	41.62	42.27	41.58	42.01	4056100
	1/20/2012	41.22	41.53	41.05	41.53	2494200
	1/19/2012	42	42.05	41.08	41.14	3743100
	1/18/2012	42.02	42.12	41.7	41.97	3108700
	1/17/2012	42.49	42.66	41.91	41.99	3281900
	1/13/2012	42.04	42.18	41.81	42.17	3131300
	1/12/2012	42.16	42.29	41.92	42.2	2506200
	1/11/2012	42.18	42.3	42	42	2572900
	1/10/2012	42.48	42.67	42.25	42.38	2895500
	1/9/2012	42.32	42.51	42.05	42.4	5642400
	1/6/2012	42.17	42.29	41.99	42.21	2628600
	1/5/2012	42.15	42.26	41.91	42.06	3784800
	1/4/2012	42.77	42.77	41.96	42.19	4496500
	1/3/2012	44.67	44.74	42.52	42.81	5298900
	12/30/2011	45	45.09	44.27	44.3	1676700
	12/29/2011	44.83	45.16	44.79	45.13	1387800
	12/28/2011	44.87	45	44.7	44.76	1639100
	12/27/2011	44.41	44.95	44.38	44.83	1269300
	12/23/2011	44.51	44.78	44.34	44.38	1794600
	12/22/2011	44.5	44.5	44.12	44.29	1585200
	12/21/2011	43.51	44.43	43.46	44.31	2812000
	12/20/2011	42.98	43.45	42.84	43.37	2861600
	12/19/2011	43.67	43.87	42.34	42.48	3526900
	12/16/2011	44.4	44.49	43.31	43.43	6010500
	12/15/2011	44.2	44.51	43.98	44.31	1990100
	12/14/2011	44.47	44.56	43.85	43.92	2418400
	AVERAGE	43.05	43.31	42.59	42.90	3688720.00
	MEDIAN	42.605	42.755	42.06	42.39	2913950
	MAXIMUM	45	45.16	44.79	45.13	12737000
	MINIMUM	41.04	41.53	40.37	41.14	1269300
TE	Date	Open	High	Low	Close	Volume
	1/27/2012	18.56	18.57	18.3	18.36	1368500
	1/26/2012	18.53	18.74	18.42	18.61	1605400
	1/25/2012	18	18.52	17.86	18.48	2178600
	1/24/2012	18.25	18.29	17.99	18.07	1341700
	1/23/2012	18.32	18.43	18.21	18.34	1235500
	1/20/2012	18.29	18.3	18.11	18.3	1198500
	1/19/2012	18.27	18.4	18.12	18.29	1622600
	1/18/2012	18.26	18.42	18.1	18.3	2130800
	1/17/2012	18.59	18.67	18.17	18.26	4030700
	1/13/2012	19	19.09	18.54	18.6	3019200
	1/12/2012	19.17	19.29	19.05	19.17	1654400
	1/11/2012	18.99	19.11	18.98	19.11	1126100
	1/10/2012	19.12	19.12	18.99	19.05	860700
	1/9/2012	18.99	19	18.86	18.95	1758300
	1/6/2012	19.05	19.08	18.91	18.94	769200
	1/5/2012	18.95	19.12	18.86	19.07	1090600
	1/4/2012	18.98	19.1	18.95	19.01	790300
	1/3/2012	19.41	19.41	18.95	18.99	1511900
	12/30/2011	19.26	19.3	19.14	19.14	809300
	12/29/2011	19.09	19.27	19.08	19.26	761700
	12/28/2011	19.21	19.25	18.98	18.99	879100

	12/27/2011	19.1	19.26	19.05	19.2	770300
	12/23/2011	18.96	19.13	18.83	19.09	959100
	12/22/2011	18.83	18.94	18.78	18.84	1295800
	12/21/2011	18.75	18.82	18.64	18.75	2760800
	12/20/2011	18.4	18.72	18.3	18.69	1625300
	12/19/2011	18.43	18.49	18.12	18.18	1139600
	12/16/2011	18.41	18.47	18.25	18.33	2196800
	12/15/2011	18.29	18.39	18.12	18.34	1296200
	12/14/2011	18.22	18.27	17.96	17.99	1138600
	AVERAGE	18.72	18.83	18.55	18.69	1497520.00
	MEDIAN	18.79	18.88	18.59	18.72	1296000
	MAXIMUM	19.41	19.41	19.14	19.26	4030700
	MINIMUM	18	18.27	17.86	17.99	761700
ALE	Date	Open	High	Low	Close	Volume
	1/27/2012	41.74	41.86	41.12	41.47	300600
	1/26/2012	41.79	41.9	41.51	41.77	340100
	1/25/2012	40.87	41.72	40.77	41.67	370300
	1/24/2012	40.99	41.16	40.8	41	120100
	1/23/2012	41.3	41.64	40.94	41.11	114300
	1/20/2012	41.15	41.49	41.15	41.33	117300
	1/19/2012	41.57	41.66	41.23	41.24	114400
	1/18/2012	41.25	41.58	41.05	41.57	130200
	1/17/2012	41.26	41.6	41.2	41.4	274000
	1/13/2012	40.71	41.12	40.69	40.98	153600
	1/12/2012	41.05	41.17	40.83	41.09	90700
	1/11/2012	41	41.25	40.95	40.96	186400
	1/10/2012	40.7	41.14	40.65	41.07	197300
	1/9/2012	40.3	40.53	40.07	40.41	347600
	1/6/2012	40.48	40.53	39.98	40.06	333400
	1/5/2012	40.79	40.87	40.46	40.5	331400
	1/4/2012	40.92	41.31	40.83	40.83	217900
	1/3/2012	42.48	42.49	40.96	41.09	190300
	12/30/2011	42.28	42.39	41.96	41.98	102500
	12/29/2011	42	42.54	42	42.4	180100
	12/28/2011	42.13	42.37	41.93	41.97	184200
	12/27/2011	41.64	42.4	41.64	42.32	116500
	12/23/2011	41.55	41.76	41.36	41.64	98600
	12/22/2011	40.71	41.6	40.66	41.49	676000
	12/21/2011	40.09	40.7	40.06	40.6	270000
	12/20/2011	40.01	40.33	40	40.2	270000
	12/19/2011	40.01	40.28	39.45	39.51	127900
	12/16/2011	39.75	40.24	39.57	39.81	482700
	12/15/2011	39.82	40.01	39.63	39.91	192200
	12/14/2011	39.79	40.12	39.33	39.4	193000
	AVERAGE	41.00	41.33	40.76	41.03	227453.33
	MEDIAN	40.995	41.4	40.83	41.09	191250
	MAXIMUM	42.48	42.54	42	42.4	676000
	MINIMUM	39.75	40.01	39.33	39.4	90700
AEP	Date	Open	High	Low	Close	Volume
	1/27/2012	41	41.01	39.92	39.95	14305700
	1/26/2012	41.23	41.53	41.01	41.28	11512300
	1/25/2012	40.55	41.44	40.27	41.38	3548200
	1/24/2012	40.57	40.74	40.41	40.67	2954800
	1/23/2012	41	41.25	40.61	40.8	4864200
	1/20/2012	41.13	41.23	40.83	41.01	4167500
	1/19/2012	41.55	41.62	41.01	41.1	4582300
	1/18/2012	41.5	41.64	41.27	41.54	2854500

	1/17/2012	41.58	41.78	41.2	41.43	4096300
	1/13/2012	41.06	41.37	41.03	41.37	2717400
	1/12/2012	41.33	41.45	41.11	41.35	2447000
	1/11/2012	41.14	41.27	41.1	41.23	3074300
	1/10/2012	41.33	41.48	41.17	41.26	4721000
	1/9/2012	40.87	41.03	40.74	40.98	6044500
	1/6/2012	40.95	40.99	40.73	40.79	3215200
	1/5/2012	40.85	41.09	40.67	40.95	4039900
	1/4/2012	40.76	41.05	40.73	40.9	3384500
	1/3/2012	41.96	41.98	40.68	40.77	4968200
	12/30/2011	41.63	41.65	41.3	41.31	1680800
	12/29/2011	41.4	41.63	41.37	41.54	1944400
	12/28/2011	41.59	41.71	41.24	41.28	1994300
	12/27/2011	41.52	41.68	41.45	41.65	2448300
	12/23/2011	41.54	41.65	41.4	41.57	2014000
	12/22/2011	41	41.42	40.9	41.37	3490600
	12/21/2011	39.92	40.99	39.92	40.85	4490000
	12/20/2011	39.75	39.97	39.63	39.94	2789400
	12/19/2011	39.89	39.95	39.15	39.29	2775500
	12/16/2011	39.85	40.04	39.46	39.66	4431700
	12/15/2011	39.04	39.81	39	39.74	5042200
	12/14/2011	39.53	39.59	38.43	38.72	8323000
	AVERAGE	40.90	41.13	40.59	40.86	4297400.00
	MEDIAN	41.03	41.32	40.785	41.055	3519400
	MAXIMUM	41.96	41.98	41.45	41.65	14305700
	MINIMUM	39.04	39.59	38.43	38.72	1680800
CNL	Date	Open	High	Low	Close	Volume
	1/27/2012	38.21	38.39	37.96	38.19	425600
	1/26/2012	38.14	38.65	37.88	38.31	567300
	1/25/2012	37.15	38.06	36.8	38	730500
	1/24/2012	36.75	37.17	36.66	37.12	816100
	1/23/2012	36.5	37.25	36.5	36.81	1095800
	1/20/2012	36.49	36.69	36.32	36.41	1115800
	1/19/2012	37.21	37.21	36.48	36.51	409000
	1/18/2012	37.34	37.34	36.85	37.13	306100
	1/17/2012	37.31	37.54	37.17	37.32	592800
	1/13/2012	37.04	37.16	36.82	37.01	380000
	1/12/2012	36.98	37.3	36.82	37.2	540000
	1/11/2012	36.55	36.88	36.42	36.84	441600
	1/10/2012	36.58	36.7	36.41	36.55	355800
	1/9/2012	36.33	36.37	36.15	36.28	438100
	1/6/2012	36.8	36.85	36.2	36.24	481700
	1/5/2012	36.97	37.03	36.66	36.8	479000
	1/4/2012	37.27	37.49	37.04	37.07	467200
	1/3/2012	38.36	38.6	37.21	37.43	884100
	12/30/2011	38.09	38.24	38.03	38.1	292900
	12/29/2011	38.1	38.31	38	38.18	296700
	12/28/2011	38.24	38.24	37.85	37.93	314100
	12/27/2011	37.95	38.29	37.83	38.17	243000
	12/23/2011	37.76	38	37.7	37.93	202600
	12/22/2011	37.72	37.85	37.57	37.71	325500
	12/21/2011	37	37.58	36.96	37.56	457800
	12/20/2011	36.6	37.08	36.54	37.04	409600
	12/19/2011	36.69	37.06	36.07	36.14	357300
	12/16/2011	36.43	36.75	36.22	36.62	1366600
	12/15/2011	35.91	36.43	35.86	36.35	343000
	12/14/2011	35.87	36.01	35.58	35.59	382900

	AVERAGE	37.14	37.42	36.89	37.15	517283.33
	MEDIAN	37.02	37.275	36.81	37.095	431850
	MAXIMUM	38.36	38.65	38.03	38.31	1366600
	MINIMUM	35.87	36.01	35.58	35.59	202600
ETR	Date	Open	High	Low	Close	Volume
	1/27/2012	71.01	71.17	70.48	70.62	779100
	1/26/2012	71.07	72.08	70.89	71.3	1299100
	1/25/2012	69.02	71.06	68.67	70.89	1156500
	1/24/2012	70.19	70.19	69.03	69.46	1479800
	1/23/2012	70.88	70.88	69.73	70.7	1720300
	1/20/2012	70.94	71.27	69.31	69.93	2346500
	1/19/2012	71.13	71.33	70.35	70.66	1361400
	1/18/2012	70.75	71.38	70.27	71.24	1385400
	1/17/2012	71.77	72.11	70.7	70.9	1254100
	1/13/2012	71.2	71.42	70.75	71.11	934000
	1/12/2012	71.75	71.84	71.22	71.43	863000
	1/11/2012	71.62	71.97	71.18	71.6	791300
	1/10/2012	72.09	72.52	71.38	72	823000
	1/9/2012	71.76	71.77	71.33	71.59	779800
	1/6/2012	72	72.09	71.3	71.5	795400
	1/5/2012	71.92	72.15	71.27	71.9	1000000
	1/4/2012	72.49	72.57	71.67	71.9	977200
	1/3/2012	73.65	73.66	72.06	72.52	1805800
	12/30/2011	73.76	73.8	73.04	73.05	786400
	12/29/2011	73.4	73.8	73.17	73.65	482700
	12/28/2011	73.52	73.75	73.04	73.14	542100
	12/27/2011	73	73.75	73	73.59	587400
	12/23/2011	73.15	73.63	72.78	73.14	603700
	12/22/2011	72.88	73.12	72.64	72.88	938400
	12/21/2011	71.81	72.91	71.81	72.76	1406400
	12/20/2011	71.76	72.3	71.64	71.98	1191900
	12/19/2011	71.62	72	70.77	70.99	985400
	12/16/2011	71.85	72.01	71.25	71.64	2065500
	12/15/2011	71.09	71.86	70.95	71.58	1208600
	12/14/2011	71.03	71.19	70.44	70.6	1040600
	AVERAGE	71.80	72.19	71.20	71.68	1113026.67
	MEDIAN	71.76	72.045	71.235	71.585	992700
	MAXIMUM	73.76	73.8	73.17	73.65	2346500
	MINIMUM	69.02	70.19	68.67	69.46	482700
WR	Date	Open	High	Low	Close	Volume
	1/27/2012	29.02	29.04	28.68	28.76	828900
	1/26/2012	28.88	29.13	28.85	29.02	1371100
	1/25/2012	28.18	28.79	27.95	28.77	1010300
	1/24/2012	28.01	28.21	27.96	28.19	668800
	1/23/2012	28.23	28.49	28.04	28.15	680100
	1/20/2012	28.14	28.28	28.08	28.19	638400
	1/19/2012	28.5	28.5	28.07	28.13	776000
	1/18/2012	28.4	28.47	28.22	28.46	623500
	1/17/2012	28.37	28.66	28.23	28.4	797900
	1/13/2012	28.35	28.39	28.2	28.36	642900
	1/12/2012	28.67	28.71	28.38	28.49	591100
	1/11/2012	28.57	28.7	28.51	28.57	1110100
	1/10/2012	28.66	28.77	28.49	28.55	942200
	1/9/2012	28.19	28.29	28	28.26	708900
	1/6/2012	28.3	28.3	28.04	28.16	1179400
	1/5/2012	28.16	28.32	27.83	28.26	1678400
	1/4/2012	28.41	28.49	28.08	28.17	1267200

	1/3/2012	29.11	29.13	28.23	28.35	783400
	12/30/2011	28.88	29.05	28.78	28.78	594700
	12/29/2011	28.78	28.98	28.71	28.96	421000
	12/28/2011	28.87	28.89	28.62	28.66	504500
	12/27/2011	28.48	28.87	28.45	28.79	409200
	12/23/2011	28.36	28.57	28.36	28.55	489600
	12/22/2011	28.32	28.34	28.16	28.23	548800
	12/21/2011	27.77	28.26	27.73	28.25	657500
	12/20/2011	27.55	27.8	27.48	27.8	685800
	12/19/2011	27.38	27.55	27.17	27.28	855600
	12/16/2011	27.35	27.52	27.13	27.29	1373000
	12/15/2011	27.09	27.34	27.04	27.23	533400
	12/14/2011	27.11	27.22	26.86	26.86	673900
	AVERAGE	28.27	28.44	28.08	28.26	801520.00
	MEDIAN	28.355	28.49	28.12	28.305	682950
	MAXIMUM	29.11	29.13	28.85	29.02	1678400
	MINIMUM	27.09	27.22	26.86	26.86	409200
AVA	Date	Open	High	Low	Close	Volume
	1/27/2012	25.54	25.55	25.32	25.53	381300
	1/26/2012	25.31	25.63	25.13	25.57	319500
	1/25/2012	24.79	25.28	24.59	25.23	345300
	1/24/2012	24.82	24.83	24.61	24.82	280000
	1/23/2012	24.96	24.98	24.78	24.86	378300
	1/20/2012	25.13	25.19	24.89	24.94	388900
	1/19/2012	25.34	25.34	24.98	25.09	298900
	1/18/2012	25.19	25.23	24.98	25.23	235600
	1/17/2012	25.33	25.42	25.08	25.14	283100
	1/13/2012	25	25.13	24.81	25.1	378800
	1/12/2012	25.32	25.34	25.08	25.19	250100
	1/11/2012	25.3	25.46	25.14	25.21	300300
	1/10/2012	25.13	25.3	25.02	25.22	603100
	1/9/2012	25.33	25.33	25.08	25.18	208800
	1/6/2012	25.41	25.48	25.24	25.25	229100
	1/5/2012	25.28	25.51	25.13	25.47	463700
	1/4/2012	25.56	25.67	25.37	25.43	389600
	1/3/2012	26.18	26.18	25.44	25.58	544600
	12/30/2011	26.06	26.12	25.75	25.75	355400
	12/29/2011	25.94	26.07	25.85	26.03	288900
	12/28/2011	26.21	26.31	25.85	25.87	337100
	12/27/2011	25.9	26.29	25.86	26.21	423000
	12/23/2011	25.87	26.03	25.87	25.96	327600
	12/22/2011	25.95	26.08	25.8	25.86	262200
	12/21/2011	25.47	25.89	25.47	25.85	443900
	12/20/2011	25.48	25.77	25.48	25.59	699000
	12/19/2011	25.35	25.59	25.04	25.18	823600
	12/16/2011	25.52	25.66	25.05	25.16	7599100
	12/15/2011	25.19	25.6	25.16	25.46	1071700
	12/14/2011	25.22	25.37	24.89	24.92	656300
	AVERAGE	25.44	25.59	25.22	25.40	652226.67
	MEDIAN	25.335	25.53	25.13	25.24	366850
	MAXIMUM	26.21	26.31	25.87	26.21	7599100
	MINIMUM	24.79	24.83	24.59	24.82	208800
HE	Date	Open	High	Low	Close	Volume
	1/27/2012	26.05	26.05	25.86	25.93	286800
	1/26/2012	25.94	26.11	25.83	26.1	531000
	1/25/2012	25.44	25.92	25.28	25.86	474400
	1/24/2012	25.52	25.61	25.43	25.5	297400

	1/23/2012	25.54	25.73	25.42	25.56	329500
	1/20/2012	25.41	25.53	25.33	25.43	503900
	1/19/2012	25.78	25.79	25.4	25.49	444800
	1/18/2012	25.75	25.81	25.56	25.76	391600
	1/17/2012	25.86	25.95	25.67	25.73	325300
	1/13/2012	25.98	25.98	25.65	25.73	401200
	1/12/2012	26.01	26.01	25.8	25.95	320600
	1/11/2012	26.01	26.13	25.84	25.91	340900
	1/10/2012	26.12	26.39	25.97	26	459100
	1/9/2012	25.95	26.02	25.83	25.87	978200
	1/6/2012	26	26.08	25.82	25.87	280800
	1/5/2012	25.75	26.08	25.52	25.96	321200
	1/4/2012	26.11	26.12	25.81	25.84	215300
	1/3/2012	26.79	26.79	26.04	26.11	437200
	12/30/2011	26.66	26.73	26.48	26.48	286400
	12/29/2011	26.47	26.67	26.47	26.62	167100
	12/28/2011	26.53	26.6	26.34	26.38	222700
	12/27/2011	26.46	26.65	26.37	26.49	239400
	12/23/2011	26.33	26.57	26.33	26.46	167900
	12/22/2011	26.18	26.4	26.15	26.27	380300
	12/21/2011	26	26.25	25.91	26.17	603000
	12/20/2011	25.86	25.99	25.74	25.97	516000
	12/19/2011	25.83	26.03	25.48	25.51	545300
	12/16/2011	25.95	26.11	25.57	25.72	1225700
	12/15/2011	26.03	26.24	25.89	25.93	686500
	12/14/2011	25.91	26.06	25.72	25.74	501800
	AVERAGE	26.01	26.15	25.82	25.94	429376.67
	MEDIAN	25.99	26.08	25.815	25.92	385950
	MAXIMUM	26.79	26.79	26.48	26.62	1225700
	MINIMUM	25.41	25.53	25.28	25.43	167100
PGC	Date	Open	High	Low	Close	Volume
	1/27/2012	41.24	41.25	40.75	40.83	1618800
	1/26/2012	41.09	41.38	40.97	41.26	1977000
	1/25/2012	40.06	41.18	39.85	41.09	3127300
	1/24/2012	40.44	40.5	40.01	40.16	2901300
	1/23/2012	40.51	40.89	40.51	40.64	2763600
	1/20/2012	40.68	40.76	39.96	40.36	6081300
	1/19/2012	41.44	41.46	40.95	41.2	2575400
	1/18/2012	41.58	41.8	41.31	41.44	2082600
	1/17/2012	41.7	42.27	41.63	41.74	1644300
	1/13/2012	41.51	41.54	40.69	41.28	3874500
	1/12/2012	41.71	41.92	41.45	41.91	2579500
	1/11/2012	41.1	41.76	40.96	41.65	3349900
	1/10/2012	41.33	41.56	41.07	41.13	1967800
	1/9/2012	41	41.08	40.73	41.05	1682900
	1/6/2012	40.96	41.18	40.76	41.06	2709100
	1/5/2012	40.92	41.09	40.4	41.05	2546600
	1/4/2012	40.85	41.01	40.74	40.85	2084300
	1/3/2012	41.42	41.52	40.62	40.82	3242100
	12/30/2011	41.5	41.58	41.19	41.22	1649100
	12/29/2011	40.98	41.47	40.95	41.45	1674300
	12/28/2011	41.12	41.24	40.62	40.85	1618200
	12/27/2011	41.15	41.8	41.07	41.71	1800300
	12/23/2011	41.14	41.6	40.99	41.09	2231800
	12/22/2011	41.26	41.29	40.86	40.95	3345200
	12/21/2011	40.46	41.16	40.38	41.06	3301000
	12/20/2011	39.77	40.43	39.7	40.37	3470800

	12/19/2011	40.01	40.16	39.22	39.44	3590700
	12/16/2011	39.77	40.25	39.6	39.98	9067200
	12/15/2011	38.99	39.68	38.86	39.56	3949700
	12/14/2011	38.56	39.12	38.44	38.61	4146700
	AVERAGE	40.81	41.13	40.51	40.86	2955110.00
	MEDIAN	41.045	41.245	40.735	41.055	2644300
	MAXIMUM	41.71	42.27	41.63	41.91	9067200
	MINIMUM	38.56	39.12	38.44	38.61	1618200
PNW	Date	Open	High	Low	Close	Volume
	1/27/2012	48.41	48.49	48.08	48.2	748900
	1/26/2012	48.32	48.86	48.1	48.53	790100
	1/25/2012	47.36	48.34	47.09	48.24	610100
	1/24/2012	47.36	47.51	47.18	47.47	1135200
	1/23/2012	47.74	48.01	47.5	47.51	627500
	1/20/2012	47.58	47.78	47.41	47.75	690100
	1/19/2012	47.84	47.84	47.26	47.49	638600
	1/18/2012	47.7	47.84	47.37	47.77	571100
	1/17/2012	47.91	48.24	47.58	47.65	1958700
	1/13/2012	47.45	47.66	47.33	47.62	2010300
	1/12/2012	47.73	47.79	47.4	47.66	1975000
	1/11/2012	47.72	47.85	47.46	47.55	630300
	1/10/2012	48.12	48.12	47.64	47.81	1097100
	1/9/2012	47.48	47.59	47	47.15	796500
	1/6/2012	47.54	47.71	47.33	47.39	634400
	1/5/2012	47.44	47.76	47.2	47.54	835600
	1/4/2012	47.89	48.05	47.46	47.51	786700
	1/3/2012	48.86	48.86	47.63	47.83	859000
	12/30/2011	48.68	48.75	48.15	48.18	541300
	12/29/2011	48.49	48.75	48.45	48.59	483300
	12/28/2011	48.7	48.78	48.3	48.36	505400
	12/27/2011	48.46	48.87	48.33	48.71	614800
	12/23/2011	48.09	48.65	47.91	48.39	498400
	12/22/2011	48.01	48.05	47.75	47.88	699700
	12/21/2011	47.42	47.94	47.35	47.8	936500
	12/20/2011	46.78	47.36	46.6	47.29	863700
	12/19/2011	45.96	46.83	45.72	46.26	1367700
	12/16/2011	46.43	46.91	45.92	46.63	3296800
	12/15/2011	45.7	46.45	45.7	46.31	1413200
	12/14/2011	45.66	45.98	45.11	45.3	1222400
	AVERAGE	47.63	47.92	47.31	47.61	994613.33
	MEDIAN	47.725	47.895	47.405	47.655	788400
	MAXIMUM	48.86	48.87	48.45	48.71	3296800
	MINIMUM	45.66	45.98	45.11	45.3	483300
POR	Date	Open	High	Low	Close	Volume
	1/27/2012	25.28	25.28	24.98	25.13	486200
	1/26/2012	25.17	25.4	25.07	25.38	398600
	1/25/2012	24.63	25.19	24.52	25.12	629500
	1/24/2012	24.71	24.75	24.58	24.71	499200
	1/23/2012	24.72	24.97	24.65	24.78	428700
	1/20/2012	24.69	24.77	24.57	24.67	870100
	1/19/2012	24.91	24.91	24.49	24.6	923400
	1/18/2012	24.8	24.91	24.67	24.91	463700
	1/17/2012	24.95	25.2	24.73	24.78	456800
	1/13/2012	24.94	25.01	24.64	24.87	928700
	1/12/2012	24.77	24.83	24.55	24.7	452500
	1/11/2012	24.64	24.75	24.56	24.69	580100
	1/10/2012	24.65	24.78	24.53	24.66	590600

	1/9/2012	24.36	24.45	24.29	24.44	580600
	1/6/2012	24.67	24.67	24.31	24.33	708800
	1/5/2012	24.74	24.78	24.51	24.61	776800
	1/4/2012	24.92	25.05	24.83	24.83	385900
	1/3/2012	25.54	25.62	24.9	25	485300
	12/30/2011	25.43	25.49	25.29	25.29	792600
	12/29/2011	25.39	25.48	25.22	25.46	525200
	12/28/2011	25.4	25.47	25.2	25.31	460800
	12/27/2011	25.18	25.54	25.18	25.42	380800
	12/23/2011	25.13	25.33	25.09	25.17	310000
	12/22/2011	24.9	25.13	24.78	25.03	648200
	12/21/2011	24.87	25.12	24.8	25.08	839500
	12/20/2011	24.75	24.9	24.69	24.85	652800
	12/19/2011	24.77	24.85	24.46	24.52	376600
	12/16/2011	24.75	24.89	24.53	24.65	860900
	12/15/2011	24.6	24.82	24.5	24.73	516000
	12/14/2011	24.4	24.52	24.26	24.36	582800
	AVERAGE	24.89	25.03	24.71	24.87	586390.00
	MEDIAN	24.785	24.94	24.645	24.805	552650
	MAXIMUM	25.54	25.62	25.29	25.46	928700
	MINIMUM	24.36	24.45	24.26	24.33	310000
UNS	Date	Open	High	Low	Close	Volume
	1/27/2012	37.33	37.39	37.06	37.21	162000
	1/26/2012	37.21	37.59	37.04	37.49	284500
	1/25/2012	36.58	37.18	36.33	37.13	193600
	1/24/2012	36.79	36.79	36.47	36.65	246800
	1/23/2012	37.15	37.4	36.68	36.89	271800
	1/20/2012	37.17	37.4	36.95	37.08	321000
	1/19/2012	37.27	37.27	36.92	37.06	366800
	1/18/2012	36.97	37.26	36.67	37.23	468100
	1/17/2012	36.9	37.27	36.88	36.95	566800
	1/13/2012	36.18	36.87	36.18	36.8	543000
	1/12/2012	36.45	36.51	36.33	36.43	394800
	1/11/2012	36.35	36.44	36.15	36.34	313600
	1/10/2012	36.39	36.39	36.12	36.31	528000
	1/9/2012	36.34	36.53	35.83	36.11	559200
	1/6/2012	36.7	36.8	36.21	36.35	898100
	1/5/2012	36.54	36.88	36.33	36.78	351900
	1/4/2012	36.54	36.71	36.48	36.61	446500
	1/3/2012	37.33	37.37	36.51	36.58	399700
	12/30/2011	37.12	37.35	36.85	36.92	366000
	12/29/2011	37.42	37.69	36.83	37.18	608100
	12/28/2011	37.86	37.94	37.44	37.45	358800
	12/27/2011	37.51	38	37.51	37.78	193200
	12/23/2011	37.58	37.8	37.5	37.6	209900
	12/22/2011	37.59	37.59	37.31	37.44	277000
	12/21/2011	36.95	37.52	36.95	37.46	222300
	12/20/2011	36.78	37.15	36.76	36.98	259000
	12/19/2011	36.7	36.94	36.35	36.43	260800
	12/16/2011	36.31	37.07	36.31	36.58	1908400
	12/15/2011	36.66	36.91	36.52	36.82	334700
	12/14/2011	36.5	36.66	36.28	36.29	389600
	AVERAGE	36.91	37.16	36.66	36.90	423466.67
	MEDIAN	36.845	37.22	36.595	36.905	355350
	MAXIMUM	37.86	38	37.51	37.78	1908400
	MINIMUM	36.18	36.39	35.83	36.11	162000

KENTUCKY POWER COMPANY

12/14/11-1/27/12

NAME/ TICKER	MARKET PRICE	BETA (VL)	DIVIDEND INCR?	CURRENT DIVIDEND	2006 EPS	2007 EPS	2008 EPS
FE	42.90	0.8	n	0.55	3.82	4.22	4.38
TE	18.69	0.85	y	0.215	1.17	1.27	0.77
ALE	41.03	0.7	y	0.445	2.77	3.08	2.82
AEP	40.86	0.7	n	0.47	2.86	2.86	2.99
CNL	37.15	0.7	n	0.313	1.36	1.32	1.7
ETR	71.68	0.7	n	0.83	5.36	5.6	6.2
WR	28.26	0.75	y	0.32	1.88	1.84	1.31
AVA	25.40	0.7	y	0.275	1.47	0.72	1.36
HE	25.94	0.7	N	0.31	1.33	1.11	1.07
PCG	40.86	0.55	n	0.455	2.76	2.78	3.22
PNW	47.61	0.7	n	0.525	3.17	2.96	2.12
POR	24.87	0.75	N	0.265	1.14	2.33	1.39
UNS	36.90	0.75	y	0.42	1.85	1.55	0.39

Beta 0.71923077

	VL S&I (2/3/12) 12 MOS FORWARD YIELD	Val Line Purchased Power	full decoupling	States in which Co. operates
First Energy Corp.	5.3	30%	√	OH,NJ,PA,MD
TECO Energy	4.9	9%		FL
ALLETE	4.4	39%		MN,WI
American Electric Power	4.7	n/a		AK,KY,IND,W
Cleco Corporation	3.4	25%		LA
Entergy Corp.	4.8	33%		AR,LA,MS,TX
Westar Energy	4.6	0%		KAN
Avista Corporation	4.8	45%		WA,IDA
Hawaiian Electric	4.9	40%	√	HI
PGE Corporation	4.5	58%	√	CA
Pinnacle West Capital	4.4	24%		AZ
Portland General	4.4	43%		OR
UniSource Energy	4.6	0%		AZ

Avg. D/P 4.59

2009 EPS	2010 EPS	2011 EPS	2012 EPS	2014-2016 EPS	2006 DPS	2007 DPS	2008 DPS
3.32	3.25	2.5	3.4	3.75	1.85	2.05	2.2
1	1.13	1.3	1.45	1.75	0.76	0.78	0.8
1.89	2.19	2.65	2.65	3.25	1.45	1.64	1.72
2.97	2.6	3.15	3.25	3.75	1.5	1.58	1.64
1.76	2.29	2.45	2.4	2.75	0.9	0.9	0.9
6.3	6.66	7.4	6	6.5	2.16	2.58	3
1.28	1.8	1.75	1.9	2.4	0.98	1.08	1.16
1.58	1.65	1.75	1.8	2	0.57	0.6	0.69
0.91	1.21	1.5	1.7	2	1.24	1.24	1.24
3.03	2.82	2.8	2.95	4	1.32	1.44	1.56
2.26	3.08	2.9	3.3	3.5	2.03	2.1	2.1
1.31	1.66	1.95	2	2.25	0.68	0.93	0.97
2.69	2.82	2.85	2.7	3.45	0.84	0.9	0.96

,WV

V,MI,OH,OK,TX,VA

2009 DPS	2010 DPS	2011 DPS	2012 DPS	2014-2016 DPS	2006 ROE(decimal)	2007 ROE(decimal)	2008 ROE(decimal)
2.2	2.2	2.2	2.2	2.3	0.139	0.146	0.162
0.8	0.82	0.85	0.89	1.05	0.141	0.132	0.081
1.76	1.76	1.78	1.8	1.95	0.116	0.118	0.1
1.64	1.71	1.85	1.9	2.1	0.12	0.114	0.113
0.9	0.98	1.12	1.25	1.6	0.083	0.078	0.096
3	3.24	3.32	3.32	3.5	0.138	0.144	0.153
1.2	1.24	1.28	1.32	1.44	0.107	0.092	0.062
0.81	1	1.1	1.18	1.4	0.08	0.042	0.074
1.24	1.24	1.24	1.24	1.3	0.099	0.072	0.065
1.68	1.82	1.82	1.82	2	0.127	0.118	0.126
2.1	2.1	2.1	2.1	2.35	0.092	0.085	0.062
1.01	1.04	1.06	1.08	1.2	0.058	0.11	0.064
1.16	1.56	1.68	1.76	2.08	0.106	0.085	0.021

2009	2010	2011	2012	2014-2016	2006	2007	2008
ROE(decimal)	ROE(decimal)	ROE(decimal)	ROE(decimal)	ROE(decimal)	BVPS	BVPS	BVPS
0.119	0.116	0.075	0.105	0.1	28.3	29.45	27.17
0.103	0.112	0.125	0.13	0.14	8.25	9.56	9.43
0.066	0.077	0.09	0.09	0.095	21.9	24.11	25.37
0.104	0.091	0.105	0.105	0.105	23.73	25.17	26.33
0.095	0.106	0.105	0.095	0.095	15.22	16.85	17.65
0.143	0.147	0.145	0.11	0.105	40.45	40.71	42.07
0.062	0.082	0.08	0.08	0.1	17.62	19.14	20.18
0.083	0.082	0.085	0.085	0.09	17.46	17.27	18.3
0.058	0.077	0.09	0.1	0.105	13.44	15.29	15.35
0.112	0.097	0.095	0.095	0.11	22.44	24.18	25.97
0.069	0.09	0.085	0.09	0.09	34.48	35.15	34.16
0.062	0.079	0.09	0.085	0.09	19.58	21.05	21.64
0.139	0.136	0.12	0.11	0.125	18.59	19.54	19.16
0.06833333							
0.10815385	0.10276923	0.09069231	0.09346154	0.09938462	0.09923077	0.09846154	0.10384615
		09.9%		09.5%		10.4%	

2009	2010	2011	2012	2014-2016	2006	2007	2008
BVPS	BVPS	BVPS	BVPS	BVPS	SHARES OUTS	SHARES OUTS	SHARES OUTS
28.08	28.03	32.05	33.3	37.25	319.21	304.84	304.84
9.75	10.1	10.55	11.1	13.25	209.5	210.9	212.9
26.41	27.26	28.3	29.45	32.75	30.4	30.8	32.6
27.49	28.33	30.4	31.85	36.75	396.67	400.43	406.07
18.5	21.76	23.65	24.8	28.25	57.57	59.94	60.04
45.54	47.53	51.05	53.75	62	202.67	193.12	189.36
20.59	21.25	22.2	22.9	24.2	87.39	95.46	108.31
19.17	19.71	20.35	21.05	22.75	52.51	52.91	54.49
15.58	15.67	16.05	16.65	19	81.46	83.43	90.52
27.88	28.55	29.55	31.15	36.75	348.14	353.72	361.06
32.69	33.86	34.75	35.9	39.5	99.96	100.49	100.89
20.5	21.14	22	22.85	25.5	62.5	62.53	62.58
20.94	22.46	23.35	24.3	27.8	35.19	35.32	35.46

2009	2010	2011	2012	2014-2016	5YR HIST	5YR PROJ
SHARES OUTS	SHARES OUTS	SHARES OUTS	SHARES OUTS	SHARES OUTS	EARN GROWTH	EARN GROWTH
304.84	304.84	418.22	418.22	418.22	0.09	0.005
213.9	214.9	216	217	220	0.125	0.105
35.2	35.8	37	38.2	40	0.035	0.06
478.05	480.81	484	488	500	0.02	0.045
60.26	60.53	60.7	60.7	60.7	0.075	0.06
189.12	178.75	176	176	171	0.1	0.005
109.07	112.13	117.5	120	128	0.01	0.085
54.84	57.12	58.5	59.5	61	0.115	0.045
92.52	94.69	96	98	110	-0.06	0.11
370.6	395.23	406	420	425	0.07	0.05
101.43	108.77	109.25	110	123	0.005	0.06
75.21	75.32	75.35	75.5	76.25	0.075	0.075
35.85	36.54	37	37	38	0.085	0.095

5YR HIST DIV GROWTH	5YR PROJ DIV GROWTH	5YR HIST BV GROWTH	5YR PROJ BV GROWTH	Zacks 2012 EPS	IBES PROJ 5-YR EPS
0.05	0.005	0.01	0.05	3.25	0.01
-0.05	0.045	0.05	0.05	1.39	0.0467
0.175	0.02	0.05	0.035	2.61	0.05
0.02	0.04	0.05	0.05	3.29	0.04
0.005	0.095	0.11	0.065	2.45	n/a
0.105	0.02	0.04	0.055	5.8	0.02
0.07	0.03	0.06	0.025	1.96	0.0609
0.1	0.09	0.04	0.03	1.77	0.0467
0	0.01	0.01	0.035	1.72	0.0803
0	0.03	0.105	0.05	3.19	0.0427
0.03	0.02	0.005	0.025	3.36	0.0533
0	0.03	0.02	0.03	1.93	0.05
0.13	0.09	0.045	0.05	2.48	0.026

KENTUCKY POWER COMPANY
DCF GROWTH RATE PARAMETERS
ELECTRIC UTILITIES

COMPANY	INTERNAL GROWTH				EXTERNAL GROWTH	
FE	RETENTION RATIO	EQUITY RETURN	"g"	BOOK VALUE ($/SHARE)	SHARES OUTS (MILLIONS)	SHARE GROWTH
2006	0.5157	13.9%	7.17%	28.30	319.21	
2007	0.5142	14.6%	7.51%	29.45	304.84	
2008	0.4977	16.2%	8.06%	27.17	304.84	
2009	0.3373	11.9%	4.01%	28.08	304.84	
2010	0.3231	11.6%	3.75%	28.03	304.84	
AVERAGE GROWTH			6.10%	1.00%		-1.14%
2011	0.1200	07.5%	0.90%		418.22	37.19%
2012	0.3529	10.5%	3.71%		418.22	17.13%
2014-2016	0.3867	10.0%	3.87%	5.00%	418.22	6.53%

COMPANY	INTERNAL GROWTH				EXTERNAL GROWTH	
TE	RETENTION RATIO	EQUITY RETURN	"g"	BOOK VALUE ($/SHARE)	SHARES OUTS (MILLIONS)	SHARE GROWTH
2006	0.3504	14.1%	4.94%	8.25	209.50	
2007	0.3858	13.2%	5.09%	9.56	210.90	
2008	-0.0390	08.1%	-0.32%	9.43	212.90	
2009	0.2000	10.3%	2.06%	9.75	213.90	
2010	0.2743	11.2%	3.07%	10.10	214.90	
AVERAGE GROWTH			2.97%	5.00%		0.64%
2011	0.3462	12.5%	4.33%		216.00	0.51%
2012	0.3862	13.0%	5.02%		217.00	0.49%
2014-2016	0.4000	14.0%	5.60%	5.00%	220.00	0.47%

COMPANY	INTERNAL GROWTH				EXTERNAL GROWTH	
ALE	RETENTION RATIO	EQUITY RETURN	"g"	BOOK VALUE ($/SHARE)	SHARES OUTS (MILLIONS)	SHARE GROWTH
2006	0.4765	11.6%	5.53%	21.90	30.40	
2007	0.4675	11.8%	5.52%	24.11	30.80	
2008	0.3901	10.0%	3.90%	25.37	32.60	
2009	0.0688	06.6%	0.45%	26.41	35.20	
2010	0.1963	07.7%	1.51%	27.26	35.80	
AVERAGE GROWTH			3.38%	5.00%		4.17%
2011	0.3283	09.0%	2.95%		37.00	3.35%
2012	0.3208	09.0%	2.89%		38.20	3.30%
2014-2016	0.4000	09.5%	3.80%	3.50%	40.00	2.24%

KENTUCKY POWER COMPANY
DCF GROWTH RATE PARAMETERS
ELECTRIC UTILITIES

COMPANY	INTERNAL GROWTH			EXTERNAL GROWTH		
AEP	RETENTION RATIO	EQUITY RETURN	"g"	BOOK VALUE ($/SHARE)	SHARES OUTS (MILLIONS)	SHARE GROWTH
2006	0.4755	12.0%	5.71%	23.73	396.67	
2007	0.4476	11.4%	5.10%	25.17	400.43	
2008	0.4515	11.3%	5.10%	26.33	406.07	
2009	0.4478	10.4%	4.66%	27.49	478.05	
2010	0.3423	09.1%	3.12%	28.33	480.81	
AVERAGE GROWTH			4.74%	5.00%		4.93%
2011	0.4127	10.5%	4.33%		484.00	0.66%
2012	0.4154	10.5%	4.36%		488.00	0.74%
2014-2016	0.4400	10.5%	4.62%	5.00%	500.00	0.79%

COMPANY	INTERNAL GROWTH			EXTERNAL GROWTH		
CNL	RETENTION RATIO	EQUITY RETURN	"g"	BOOK VALUE ($/SHARE)	SHARES OUTS (MILLIONS)	SHARE GROWTH
2006	0.3382	08.3%	2.81%	15.22	57.57	
2007	0.3182	07.8%	2.48%	16.85	59.94	
2008	0.4706	09.6%	4.52%	17.65	60.04	
2009	0.4886	09.5%	4.64%	18.50	60.26	
2010	0.5721	10.6%	6.06%	21.76	60.53	
AVERAGE GROWTH			4.10%	11.00%		1.26%
2011	0.5429	10.5%	5.70%		60.70	0.28%
2012	0.4792	09.5%	4.55%		60.70	0.14%
2014-2016	0.4182	09.5%	3.97%	6.50%	60.70	0.06%

COMPANY	INTERNAL GROWTH			EXTERNAL GROWTH		
ETR	RETENTION RATIO	EQUITY RETURN	"g"	BOOK VALUE ($/SHARE)	SHARES OUTS (MILLIONS)	SHARE GROWTH
2006	0.5970	13.8%	8.24%	40.45	202.67	
2007	0.5393	14.4%	7.77%	40.71	193.12	
2008	0.5161	15.3%	7.90%	42.07	189.36	
2009	0.5238	14.3%	7.49%	45.54	189.12	
2010	0.5135	14.7%	7.55%	47.53	178.75	
AVERAGE GROWTH			7.79%	4.00%		-3.09%
2011	0.5514	14.5%	7.99%		176.00	-1.54%
2012	0.4467	11.0%	4.91%		176.00	-0.77%
2014-2016	0.4615	10.5%	4.85%	5.50%	171.00	-0.88%

KENTUCKY POWER COMPANY
DCF GROWTH RATE PARAMETERS
ELECTRIC UTILITIES

COMPANY	INTERNAL GROWTH				EXTERNAL GROWTH	
WR	RETENTION RATIO	EQUITY RETURN	"g"	BOOK VALUE ($/SHARE)	SHARES OUTS (MILLIONS)	SHARE GROWTH
2006	0.4787	10.7%	5.12%	17.62	87.39	
2007	0.4130	09.2%	3.80%	19.14	95.46	
2008	0.1145	06.2%	0.71%	20.18	108.31	
2009	0.0625	06.2%	0.39%	20.59	109.07	
2010	0.3111	08.2%	2.55%	21.25	112.13	
AVERAGE GROWTH			2.51%	6.00%		6.43%
2011	0.2686	08.0%	2.15%		117.50	4.79%
2012	0.3053	08.0%	2.44%		120.00	3.45%
2014-2016	0.4000	10.0%	4.00%	2.50%	128.00	2.68%

COMPANY	INTERNAL GROWTH				EXTERNAL GROWTH	
AVA	RETENTION RATIO	EQUITY RETURN	"g"	BOOK VALUE ($/SHARE)	SHARES OUTS (MILLIONS)	SHARE GROWTH
2006	0.6122	08.0%	4.90%	17.46	52.51	
2007	0.1667	04.2%	0.70%	17.27	52.91	
2008	0.4926	07.4%	3.65%	18.30	54.49	
2009	0.4873	08.3%	4.04%	19.17	54.84	
2010	0.3939	08.2%	3.23%	19.71	57.12	
AVERAGE GROWTH			3.30%	4.00%		2.13%
2011	0.3714	08.5%	3.16%		58.50	2.42%
2012	0.3444	08.5%	2.93%		59.50	2.06%
2014-2016	0.3000	09.0%	2.70%	3.00%	61.00	1.32%

COMPANY	INTERNAL GROWTH				EXTERNAL GROWTH	
HE	RETENTION RATIO	EQUITY RETURN	"g"	BOOK VALUE ($/SHARE)	SHARES OUTS (MILLIONS)	SHARE GROWTH
2006	0.0677	09.9%	0.67%	13.44	81.46	
2007	-0.1171	07.2%	-0.84%	15.29	83.43	
2008	-0.1589	06.5%	-1.03%	15.35	90.52	
2009	-0.3626	05.8%	-2.10%	15.58	92.52	
2010	-0.0248	07.7%	-0.19%	15.67	94.69	
AVERAGE GROWTH			-0.70%	1.00%		3.83%
2011	0.1733	09.0%	1.56%		96.00	1.38%
2012	0.2706	10.0%	2.71%		98.00	1.73%
2014-2016	0.3500	10.5%	3.68%	3.50%	110.00	3.04%

KENTUCKY POWER COMPANY
DCF GROWTH RATE PARAMETERS
ELECTRIC UTILITIES

COMPANY	INTERNAL GROWTH				EXTERNAL GROWTH	
PCG	RETENTION RATIO	EQUITY RETURN	"g"	BOOK VALUE ($/SHARE)	SHARES OUTS (MILLIONS)	SHARE GROWTH
2006	0.5217	12.7%	6.63%	22.44	348.14	
2007	0.4820	11.8%	5.69%	24.18	353.72	
2008	0.5155	12.6%	6.50%	25.97	361.06	
2009	0.4455	11.2%	4.99%	27.88	370.60	
2010	0.3546	09.7%	3.44%	28.55	395.23	
AVERAGE GROWTH			5.45%	10.50%		3.22%
2011	0.3500	09.5%	3.33%		406.00	2.72%
2012	0.3831	09.5%	3.64%		420.00	3.09%
2014-2016	0.5000	11.0%	5.50%	5.00%	425.00	1.46%

COMPANY	INTERNAL GROWTH				EXTERNAL GROWTH	
PNW	RETENTION RATIO	EQUITY RETURN	"g"	BOOK VALUE ($/SHARE)	SHARES OUTS (MILLIONS)	SHARE GROWTH
2006	0.3596	09.2%	3.31%	34.48	99.96	
2007	0.2905	08.5%	2.47%	35.15	100.49	
2008	0.0094	06.2%	0.06%	34.16	100.89	
2009	0.0708	06.9%	0.49%	32.69	101.43	
2010	0.3182	09.0%	2.86%	33.86	108.77	
AVERAGE GROWTH			1.84%	0.50%		2.13%
2011	0.2759	08.5%	2.34%		109.25	0.44%
2012	0.3636	09.0%	3.27%		110.00	0.56%
2014-2016	0.3286	09.0%	2.96%	2.50%	123.00	2.49%

COMPANY	INTERNAL GROWTH				EXTERNAL GROWTH	
POR	RETENTION RATIO	EQUITY RETURN	"g"	BOOK VALUE ($/SHARE)	SHARES OUTS (MILLIONS)	SHARE GROWTH
2006	0.4035	05.8%	2.34%	19.58	62.50	
2007	0.6009	11.0%	6.61%	21.05	62.53	
2008	0.3022	06.4%	1.93%	21.64	62.58	
2009	0.2290	06.2%	1.42%	20.50	75.21	
2010	0.3735	07.9%	2.95%	21.14	75.32	
AVERAGE GROWTH			3.05%	2.00%		4.77%
2011	0.4564	09.0%	4.11%		75.35	0.04%
2012	0.4600	08.5%	3.91%		75.50	0.12%
2014-2016	0.4667	09.0%	4.20%	3.00%	76.25	0.25%

KENTUCKY POWER COMPANY
DCF GROWTH RATE PARAMETERS
ELECTRIC UTILITIES

COMPANY	INTERNAL GROWTH				EXTERNAL GROWTH	
UNS	RETENTION RATIO	EQUITY RETURN	"g"	BOOK VALUE ($/SHARE)	SHARES OUTS (MILLIONS)	SHARE GROWTH
2006	0.5459	10.6%	5.79%	18.59	35.19	
2007	0.4194	08.5%	3.56%	19.54	35.32	
2008	-1.4615	02.1%	-3.07%	19.16	35.46	
2009	0.5688	13.9%	7.91%	20.94	35.85	
2010	0.4468	13.6%	6.08%	22.46	36.54	
AVERAGE GROWTH			4.05%	4.50%		0.95%
2011	0.4105	12.0%	4.93%		37.00	1.26%
2012	0.3481	11.0%	3.83%		37.00	0.63%
2014-2016	0.3971	12.5%	4.96%	5.00%	38.00	0.79%

Data from Value Line Ratings and Reports, November 4, December 23, 2011 and February 3, 2012

KENTUCKY POWER COMPANY

DCF GROWTH RATES
ELECTRIC UTILITIES

COMPANY	br	+	sv=g*(1-(1/(M/B)))	=	g
FE	4.00%	+	0.00% (1 - (1/ 1.34))	=	4.00%
TE	5.25%	+	0.50% (1 - (1/ 1.77))	=	5.47%
ALE	3.75%	+	3.00% (1 - (1/ 1.45))	=	4.68%
AEP	4.25%	+	1.75% (1 - (1/ 1.34))	=	4.70%
CNL	6.00%	+	0.50% (1 - (1/ 1.57))	=	6.18%
ETR	4.75%	+	0.00% (1 - (1/ 1.40))	=	4.75%
WR	4.50%	+	3.25% (1 - (1/ 1.27))	=	5.20%
AVA	4.50%	+	1.50% (1 - (1/ 1.25))	=	4.80%
HE	4.00%	+	3.00% (1 - (1/ 1.62))	=	5.14%
PCG	5.25%	+	2.00% (1 - (1/ 1.38))	=	5.80%
PNW	3.50%	+	2.25% (1 - (1/ 1.37))	=	4.11%
POR	4.25%	+	1.00% (1 - (1/ 1.13))	=	4.37%
UNS	5.50%	+	0.75% (1 - (1/ 1.58))	=	5.78%

Average Market-to-Book Ratio = 1.42

FE	=	First Energy Corp.
TE	=	TECO Energy
ALE	=	ALLETE
AEP	=	American Electric Power
CNL	=	Cleco Corporation
ETR	=	Entergy Corp.
WR	=	Westar Energy
AVA	=	Avista Corporation
HE	=	Hawaiian Electric
PCG	=	PGE Corporation
PNW	=	Pinnacle West Capital
POR	=	Portland General
UNS	=	UniSource Energy

g*= expected growth in number of shares outstanding

KENTUCKY POWER COMPANY

GROWTH RATE COMPARISON
ELECTRIC UTILITIES

	DCF	Value Line Projected			Zacks	Value Line Historic			Zacks & VL	5-yr Compound Hist.		
COMPANY	Growth	EPS	DPS	BVPS	EPS	EPS	DPS	BVPS	AVGS.	EPS	DPS	BVPS
FE	4.00%	0.50%	0.50%	5.00%	1.00%	9.00%	5.00%	1.00%	3.14%	-8.13%	3.53%	2.52%
TE	5.47%	10.50%	4.50%	5.00%	4.67%	######	-5.00%	5.00%	5.31%	2.13%	2.26%	5.04%
ALE	4.68%	6.00%	2.00%	3.50%	5.00%	3.50%	17.50%	5.00%	6.07%	-0.88%	4.19%	5.26%
AEP	4.70%	4.50%	4.00%	5.00%	4.00%	2.00%	2.00%	5.00%	3.79%	1.95%	4.28%	5.08%
CNL	6.18%	6.00%	9.50%	6.50%	n/a	7.50%	0.50%	11.00%	6.83%	12.49%	4.47%	9.22%
ETR	4.75%	0.50%	2.00%	5.50%	2.00%	######	10.50%	4.00%	4.93%	6.66%	8.98%	4.76%
WR	5.20%	8.50%	3.00%	2.50%	6.09%	1.00%	7.00%	6.00%	4.87%	-1.42%	5.49%	4.73%
AVA	4.80%	4.50%	9.00%	3.00%	4.67%	######	10.00%	4.00%	6.67%	3.55%	14.05%	3.11%
HE	5.14%	11.00%	1.00%	3.50%	8.03%	-6.00%	0.00%	1.00%	2.65%	2.43%	0.00%	3.61%
PCG	5.80%	5.00%	3.00%	5.00%	4.27%	7.00%	0.00%	10.50%	4.97%	0.29%	6.63%	5.66%
PNW	4.11%	6.00%	2.00%	2.50%	5.33%	0.50%	3.00%	0.50%	2.83%	-1.76%	0.68%	0.16%
POR	4.37%	7.50%	3.00%	3.00%	5.00%	7.50%	0.00%	2.00%	4.00%	11.33%	9.28%	2.36%
UNS	5.78%	9.50%	9.00%	5.00%	2.60%	8.50%	13.00%	4.50%	7.44%	9.03%	14.87%	4.67%
		6.15%	4.04%	4.23%		5.73%	4.88%	4.58%		2.90%	6.06%	4.32%
AVERAGES	5.00%		4.81%		4.39%		5.06%		4.88%		4.42%	

IBES growth rates: FE-1.85%, TE-4.93%, ALE-5.0%, AEP-3.23%, CNL-3.0%, ETR-(3.5%), WR-5.2%, AVA-4.5%, HE-13.1%, PCG-1.45%, PNW-5.59%,POR-5.88%, UNS-3.0%.

Exhibit__(SGH-1)
Schedule 6

KENTUCKY POWER COMPANY

STOCK PRICE, DIVIDENDS, YIELDS
ELECTRIC UTILITIES

COMPANY	AVG. STOCK PRICE 12/14/11-1/27/12 (PER SHARE)		ANNUALIZED DIVIDEND (PER SHARE)	DIVIDEND YIELD
FE	$42.90		$2.20	5.13%
TE	$18.69	*	$0.91	4.85%
ALE	$41.03	*	$1.86	4.54%
AEP	$40.86		$1.88	4.60%
CNL	$37.15		$1.25	3.37%
ETR	$71.68		$3.32	4.63%
WR	$28.26	*	$1.35	4.76%
AVA	$25.40	*	$1.15	4.54%
HE	$25.94		$1.24	4.78%
PCG	$40.86		$1.82	4.45%
PNW	$47.61		$2.10	4.41%
POR	$24.87		$1.06	4.26%
UNS	$36.90	*	$1.78	4.82%
			AVERAGE	**4.55%**

*Dividend yield adjusted by (1+g) derived on CA-405.

KENTUCKY POWER COMPANY

DCF COST OF EQUITY CAPITAL
ELECTRIC UTILITIES

COMPANY	DIVIDEND YIELD FROM DOD-211	GROWTH RATE FROM DOD-209	DCF COST OF EQUITY CAPITAL
FE	5.13%	4.00%	9.13%
TE	4.85%	5.47%	10.32%
ALE	4.54%	4.68%	9.22%
AEP	4.60%	4.70%	9.30%
CNL	3.37%	6.18%	9.55%
ETR	4.63%	4.75%	9.38%
WR	4.76%	5.20%	9.96%
AVA	4.54%	4.80%	9.34%
HE	4.78%	5.14%	9.92%
PCG	4.45%	5.80%	10.26%
PNW	4.41%	4.11%	8.52%
POR	4.26%	4.37%	8.63%
UNS	4.82%	5.78%	10.59%
		OVERALL AVERAGE	**9.55%**
		STANDARD DEVIATION	**0.63%**

Exhibit__(SGH-1)
Schedule 8

KENTUCKY POWER COMPANY

CAPM COST OF EQUITY CAPITAL
ELECTRIC UTILITIES

k = rf + B (rm - rf)

[rf]* = 4.00%
[rm - rf]† = 4.4% (geometric mean)
[rm - rf]† = 6.0% (arithmetic mean)
[rm - rf]†† = 5.30%
Average Beta = 0.72

k = 4.00% + 0.72 (4.40%/5.30%/6.0%)
k = 4.00% + 3.16%/3.81%/4.31%
k = **7.16%/7.81%/8.32%**

*Current T-Bond yields, six-week average yield from Value Line Selection & Opinion (5/9/08-6/13
†Geometric and arithmetic market risk premiums from 2010 Ibbotson m SBBI Valuation Yearbook
†† Mid-point long- and short-term market risk premium from Brealey, R., Meyers, S., Allen, F., Prin
of Corporate Finance, 8th Edition, McGraw-Hill, Irwin, Boston MA, 2006, pp. 149, 154, 222.

Exibit__(SGH-1)
Schedule 10

KENTUCKY POWER COMPANY

MODIFIED EARNINGS-PRICE RATIO ANALYSIS
ELECTRIC UTILITIES

COMPANY	Zack's 2012 Earnings (Per Share) [1]	Market Price (Per share) [2]	Earnings-Price Ratio [3]=[1]/[2]		Current R.O.E. 2012 [4]	Projected R.O.E. 2014-2016 [5]
FE	$3.25	$42.90	7.58%		10.50%	10.00%
TE	$1.39	$18.69	7.44%		13.00%	14.00%
ALE	$2.61	$41.03	6.36%		9.00%	9.50%
AEP	$3.29	$40.86	8.05%		10.50%	10.50%
CNL	$2.45	$37.15	6.59%		9.50%	9.50%
ETR	$5.80	$71.68	8.09%		11.00%	10.50%
WR	$1.96	$28.26	6.93%		8.00%	10.00%
AVA	$1.77	$25.40	6.97%		8.50%	9.00%
HE	$1.72	$25.94	6.63%		10.00%	10.50%
PCG	$3.19	$40.86	7.81%		9.50%	11.00%
PNW	$3.36	$47.61	7.06%		9.00%	9.00%
POR	$1.93	$24.87	7.76%		8.50%	9.00%
UNS	$2.48	$36.90	6.72%		11.00%	12.50%
		OVERALL AVERAGE	7.23%		9.85%	
		CURRENT M.E.P.R.		**8.54%**		
		OVERALL AVERAGE	7.23%			10.38%
		PROJECTED M.E.P.R.			**8.81%**	

KENTUCKY POWER COMPANY

MARKET-TO-BOOK RATIO ANALYSIS
ELECTRIC UTILITIES

k = R.O.E.(1-b)/(M/B) + g
[2012]

COMPANY										MARKET-TO-BOOK COST OF EQUITY
FE	k=	#####	(1-	0.3529	)/	1.34	+	4.00%	=	9.08%
TE	k=	#####	(1-	0.3862	)/	1.77	+	5.47%	=	9.97%
ALE	k=	9.0%	(1-	0.3208	)/	1.45	+	4.68%	=	8.90%
AEP	k=	#####	(1-	0.4154	)/	1.34	+	4.70%	=	9.27%
CNL	k=	9.5%	(1-	0.4792	)/	1.57	+	6.18%	=	9.33%
ETR	k=	#####	(1-	0.4467	)/	1.40	+	4.75%	=	9.09%
WR	k=	8.0%	(1-	0.3053	)/	1.27	+	5.20%	=	9.56%
AVA	k=	8.5%	(1-	0.3444	)/	1.25	+	4.80%	=	9.26%
HE	k=	#####	(1-	0.2706	)/	1.62	+	5.14%	=	9.66%
PCG	k=	9.5%	(1-	0.3831	)/	1.38	+	5.80%	=	10.04%
PNW	k=	9.0%	(1-	0.3636	)/	1.37	+	4.11%	=	8.29%
POR	k=	8.5%	(1-	0.4600	)/	1.13	+	4.37%	=	8.43%
UNS	k=	#####	(1-	0.3481	)/	1.58	+	5.78%	=	10.31%
								OVERALL AVERAGE		**9.32%**
								STANDARD DEVIATION		**0.60%**

Note: Equity returns and retention ratios based on Value Line current year projections.

KENTUCKY POWER COMPANY

MARKET-TO-BOOK RATIO ANALYSIS
ELECTRIC UTILITIES

k = R.O.E.(1-b)/(M/B) + g
[2014-2016]

COMPANY									MARKET-TO-BOOK COST OF EQUITY
FE	k=	10.0%	(1- #####)/	1.34	+	4.00%		=	8.58%
TE	k=	14.0%	(1- #####)/	1.77	+	5.47%		=	10.21%
ALE	k=	9.5%	(1- #####)/	1.45	+	4.68%		=	8.61%
AEP	k=	10.5%	(1- #####)/	1.34	+	4.70%		=	9.07%
CNL	k=	9.5%	(1- #####)/	1.57	+	6.18%		=	9.70%
ETR	k=	10.5%	(1- #####)/	1.40	+	4.75%		=	8.78%
WR	k=	10.0%	(1- #####)/	1.27	+	5.20%		=	9.91%
AVA	k=	9.0%	(1- #####)/	1.25	+	4.80%		=	9.85%
HE	k=	10.5%	(1- #####)/	1.62	+	5.14%		=	9.37%
PCG	k=	11.0%	(1- #####)/	1.38	+	5.80%		=	9.78%
PNW	k=	9.0%	(1- #####)/	1.37	+	4.11%		=	8.52%
POR	k=	9.0%	(1- #####)/	1.13	+	4.37%		=	8.61%
UNS	k=	12.5%	(1- #####)/	1.58	+	5.78%		=	10.54%
							OVERALL AVERAGE		**9.35%**
							STANDARD DEVIATION		**0.70%**

Note: Equity returns and retention ratios based on Value Line three- to five-year projections.

Microsoft Word - Sch9

KENTUCKY POWER COMPANY

PROOF

If market price exceeds book value,
the market-to-book ratio is greater than 1.0,
and the earnings-price ratio understates the cost of capital.

MP = market price
BV = book value
i = cost of equity capital
r = earned return
E = earnings

1. At MP = BV, $i = r = \frac{E}{MP}$.
2. $E = rBV$.
3. Then, $\frac{E}{MP} = \frac{rBV}{MP}$.
4. When BV < MP, *i.e.*, $\frac{BV}{MP} < 1$, then,
    a. $\frac{E}{MP} < r$, since $\frac{E}{MP} = \frac{rBV}{MP} < r$, because $\frac{BV}{MP} < 1$;
    b. $i < r$, since at $\frac{BV}{MP} = 1$, $i = \frac{E}{MP} = \frac{rBV}{MP}$, but if $\frac{BV}{MP} < 1$, then $i < r$; and
    c. $\frac{E}{MP} < i$, since at $\frac{BV}{MP} = 1$, $i = \frac{E}{MP} = \frac{rBV}{MP}$, but if $\frac{BV}{MP} < 1$, then $\frac{E}{MP} < i$, because,
        1) $\frac{BV}{MP} < 1$, through MP increasing, and, if so, $\frac{E}{MP}$ decreases, therefore, $\frac{E}{MP} < i$, or
        2) $\frac{BV}{MP} < 1$, through BV decreasing, and, if so, given $E = rBV$, $\frac{E}{MP}$ decreases, therefore, $\frac{E}{MP} < i$.
5. Ergo, $\frac{E}{MP} < i < r$, the earnings-price ratio is lower than the cost of capital, which is lower than the earned return.

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xerox

KENTUCKY POWER COMPANY
OVERALL COST OF CAPITAL

Type of Capital	AMOUNT [1]	PERCENT [2]	COST RATE [3]	WT. AVG. COST RATE [4]=[2]x[3]
Common Equity	$465,314,088	43.94%	9.20%	4.04%
Short-term Debt	$0	0.00%	0.83%	0.00%
A/R Financing	$43,588,933	4.12%	1.22%	0.05%
Long-term Debt	$550,000,000	51.94%	6.48%	3.37%
Totals	$1,058,903,021	100.00%		**7.41%**

PRE-TAX INTEREST COVERAGE* = 2.87x

*Assuming the Company experiences, prospectively, a combined income tax rate of 36.6%, the pre-tax overall return would be 9.79% [7.41%-(3.37+0.05%) = 4.04%/(1-36.5%) = 6.38%+(3. That pre-tax overall return (9.79%), divided by the weighted cost of debt (3.37+0.05%), indicates a pre-tax interest coverage level of 2.87 times.

Sch12.xls

AEP
Coverage Ratios

		2006	2007	2008	2009	2010
1)	pre-tax earning	1483	1663	2015	1938	1849
2)	Interest Exp	729	838	957	973	999
3) = (1+2)/2	Coverage	3.034293553	2.984486874	3.10553814	2.991778006	2.850850851
						2.993389485

Data from AEP 2010 SEC form 10-K, Exhbit 12

KPCO
Coverage

	2008	2009	2010
per-tax earns	53420	33586	32427
interest exp	36442	33812	34535
coverage	2.465891005	1.993315982	1.938960475
			2.132722487

VL-stockmkt-graph(DowJones).pdf

VALUE LINE
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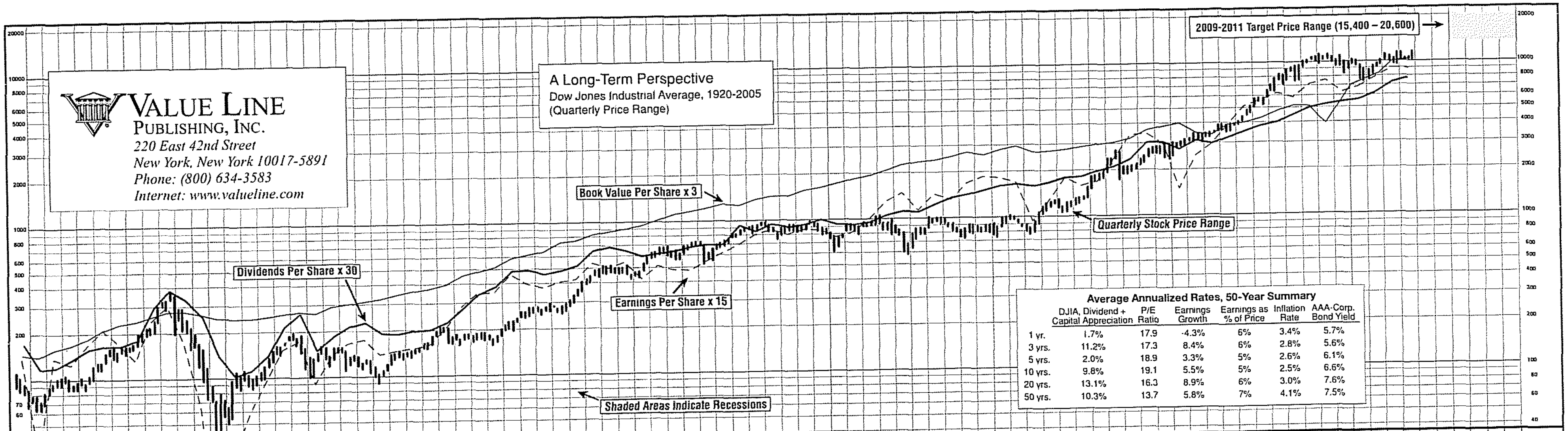
A Long-Term Perspective
Dow Jones Industrial Average, 1920-2005
(Quarterly Price Range)



Average Annualized Rates, 50-Year Summary

	DJIA, Dividend + Capital Appreciation	P/E Ratio	Earnings Growth	Earnings as % of Price	Inflation Rate	AAA-Corp. Bond Yield
1 yr.	1.7%	17.9	-4.3%	6%	3.4%	5.7%
3 yrs.	11.2%	17.3	8.4%	6%	2.8%	5.6%
5 yrs.	2.0%	18.9	3.3%	5%	2.6%	6.1%
10 yrs.	9.8%	19.1	5.5%	5%	2.5%	6.6%
20 yrs.	13.1%	16.3	8.9%	6%	3.0%	7.6%
50 yrs.	10.3%	13.7	5.8%	7%	4.1%	7.5%

1stQtrKPCo2011.pdf

Kentucky Power Company

2011 First Quarter Report

Financial Statements

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GLOSSARY OF TERMS

When the following terms and abbreviations appear in the text of this report, they have the meanings indicated below.

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP or Parent	American Electric Power Company, Inc.
AEP Credit	AEP Credit, Inc., a subsidiary of AEP which factors accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP East companies	APCo, CSPCo, I&M, KPCo and OPCo.
AEP Power Pool	Members are APCo, CSPCo, I&M, KPCo and OPCo. The Pool shares the generation, cost of generation and resultant wholesale off-system sales of the member companies.
AEP System or the System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEPSC	American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
CO_2	Carbon Dioxide and other greenhouse gases.
CSPCo	Columbus Southern Power Company, an AEP electric utility subsidiary.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
GAAP	Accounting Principles Generally Accepted in the United States of America.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
MISO	Midwest Independent Transmission System Operator.
MMBtu	Million British Thermal Units.
MTM	Mark-to-Market.
MW	Megawatt.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefit Plans.
OTC	Over the counter.
OVEC	Ohio Valley Electric Corporation, which is 43.47% owned by AEP.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generating plant, consisting of two 1,300 MW coal-fired generating units near Rockport, Indiana.
RTO	Regional Transmission Organization.
SIA	System Integration Agreement.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
Utility Money Pool	AEP System's Utility Money Pool.
VIE	Variable Interest Entity.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2011 and 2010
(in thousands)
(Unaudited)

	2011	2010
REVENUES		
Electric Generation, Transmission and Distribution	$ 179,091	$ 162,496
Sales to AEP Affiliates	16,915	11,332
Other Revenues	112	90
TOTAL REVENUES	196,118	173,918
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	62,835	52,922
Purchased Electricity for Resale	5,002	4,870
Purchased Electricity from AEP Affiliates	50,470	51,997
Other Operation	16,115	15,085
Maintenance	10,997	8,215
Depreciation and Amortization	13,386	13,095
Taxes Other Than Income Taxes	2,036	3,054
TOTAL EXPENSES	160,841	149,238
OPERATING INCOME	35,277	24,680
Other Income (Expense):		
Interest Income	106	45
Allowance for Equity Funds Used During Construction	235	217
Interest Expense	(9,199)	(9,139)
INCOME BEFORE INCOME TAX EXPENSE	26,419	15,803
Income Tax Expense	9,549	6,312
NET INCOME	$ 16,870	$ 9,491

The common stock of KPCo is wholly-owned by AEP.

See Condensed Notes to Condensed Financial Statements.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2011 and 2010
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2009	$ 50,450	$ 238,750	$ 143,185	$ (601)	$ 431,784
Common Stock Dividends			(5,000)		(5,000)
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					426,784
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $190				(352)	(352)
NET INCOME			9,491		9,491
TOTAL COMPREHENSIVE INCOME					9,139
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2010	$ 50,450	$ 238,750	$ 147,676	$ (953)	$ 435,923
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2010	$ 50,450	$ 238,750	$ 157,467	$ (451)	$ 446,216
Common Stock Dividends			(5,000)		(5,000)
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					441,216
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $73				135	135
NET INCOME			16,870		16,870
TOTAL COMPREHENSIVE INCOME					17,005
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2011	$ 50,450	$ 238,750	$ 169,337	$ (316)	$ 458,221

See Condensed Notes to Condensed Financial Statements.

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
ASSETS
March 31, 2011 and December 31, 2010
(in thousands)
(Unaudited)

	2011	2010
CURRENT ASSETS		
Cash and Cash Equivalents	$ 656	$ 281
Advances to Affiliates	93,437	67,060
Accounts Receivable:		
Customers	11,830	25,475
Affiliated Companies	14,109	17,616
Miscellaneous	548	587
Allowance for Uncollectible Accounts	(665)	(623)
Total Accounts Receivable	25,822	43,055
Fuel	15,848	16,640
Materials and Supplies	18,527	24,378
Risk Management Assets	8,261	8,697
Accrued Tax Benefits	-	1,420
Margin Deposits	4,135	5,357
Prepayments and Other Current Assets	1,816	1,497
TOTAL CURRENT ASSETS	168,502	168,385
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	554,538	553,589
Transmission	452,684	444,303
Distribution	595,380	590,606
Other Property, Plant and Equipment	63,770	63,982
Construction Work in Progress	28,569	34,093
Total Property, Plant and Equipment	1,694,941	1,686,573
Accumulated Depreciation and Amortization	552,435	542,443
TOTAL PROPERTY, PLANT AND EQUIPMENT - NET	1,142,506	1,144,130
OTHER NONCURRENT ASSETS		
Regulatory Assets	210,702	213,593
Long-term Risk Management Assets	8,560	8,030
Deferred Charges and Other Noncurrent Assets	36,412	37,946
TOTAL OTHER NONCURRENT ASSETS	255,674	259,569
TOTAL ASSETS	$ 1,566,682	$ 1,572,084

See Condensed Notes to Condensed Financial Statements.

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
LIABILITIES AND SHAREHOLDER'S EQUITY
March 31, 2011 and December 31, 2010
(Unaudited)

	2011	2010
	(in thousands)	
CURRENT LIABILITIES		
Accounts Payable:		
General	$ 29,859	$ 33,334
Affiliated Companies	27,907	45,790
Risk Management Liabilities	4,903	5,959
Customer Deposits	20,042	19,692
Accrued Taxes	26,341	23,741
Accrued Interest	5,821	7,570
Other Current Liabilities	26,433	26,227
TOTAL CURRENT LIABILITIES	141,306	162,313
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	528,930	528,888
Long-term Debt – Affiliated	20,000	20,000
Long-term Risk Management Liabilities	2,866	2,303
Deferred Income Taxes	319,577	316,389
Regulatory Liabilities and Deferred Investment Tax Credits	35,643	34,991
Employee Benefits and Pension Obligations	48,620	49,298
Deferred Credits and Other Noncurrent Liabilities	11,519	11,686
TOTAL NONCURRENT LIABILITIES	967,155	963,555
TOTAL LIABILITIES	1,108,461	1,125,868
Rate Matters (Note 2)		
Commitments and Contingencies (Note 3)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $50 Per Share:		
Authorized – 2,000,000 Shares		
Outstanding – 1,009,000 Shares	50,450	50,450
Paid-in Capital	238,750	238,750
Retained Earnings	169,337	157,467
Accumulated Other Comprehensive Income (Loss)	(316)	(451)
TOTAL COMMON SHAREHOLDER'S EQUITY	458,221	446,216
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$ 1,566,682	$ 1,572,084

See Condensed Notes to Condensed Financial Statements.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2011 and 2010
(in thousands)
(Unaudited)

	2011	2010
OPERATING ACTIVITIES		
Net Income	$ 16,870	$ 9,491
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	13,386	13,095
Deferred Income Taxes	2,384	950
Allowance for Equity Funds Used During Construction	(235)	(217)
Mark-to-Market of Risk Management Contracts	(433)	(3,573)
Fuel Over/Under-Recovery, Net	956	1,665
Change in Other Noncurrent Assets	3,705	3,144
Change in Other Noncurrent Liabilities	645	(391)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	17,240	1,721
Fuel, Materials and Supplies	6,643	9,818
Accounts Payable	(20,593)	(11,191)
Customer Deposits	350	625
Accrued Taxes, Net	2,581	5,010
Other Current Assets	876	(1,242)
Other Current Liabilities	163	(4,110)
Net Cash Flows from Operating Activities	44,538	24,795
INVESTING ACTIVITIES		
Construction Expenditures	(12,515)	(12,980)
Change in Advances to Affiliates, Net	(26,377)	(5,817)
Proceeds from Sales of Assets	90	142
Other Investing Activities	27	(46)
Net Cash Flows Used for Investing Activities	(38,775)	(18,701)
FINANCING ACTIVITIES		
Change in Advances from Affiliates, Net	-	(485)
Principal Payments for Capital Lease Obligations	(388)	(437)
Dividends Paid on Common Stock	(5,000)	(5,000)
Net Cash Flows Used for Financing Activities	(5,388)	(5,922)
Net Increase in Cash and Cash Equivalents	375	172
Cash and Cash Equivalents at Beginning of Period	281	494
Cash and Cash Equivalents at End of Period	$ 656	$ 666
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 10,747	$ 10,535
Net Cash Paid for Income Taxes	188	-
Noncash Acquisitions Under Capital Leases	-	4,108
Construction Expenditures Included in Current Liabilities at March 31,	2,891	1,980

See Condensed Notes to Condensed Financial Statements.

INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS

1. Significant Accounting Matters
2. Rate Matters
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4. Benefit Plans
5. Business Segments
6. Derivatives and Hedging
7. Fair Value Measurements
8. Income Taxes
9. Financing Activities
10. Cost Reduction Initiatives

1. SIGNIFICANT ACCOUNTING MATTERS

General

The unaudited condensed financial statements and footnotes were prepared in accordance with GAAP for interim financial information. Accordingly, they do not include all of the information and footnotes required by GAAP for complete annual financial statements.

In the opinion of management, the unaudited condensed interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair presentation of the net income, financial position and cash flows for the interim periods. Net income for the three months ended March 31, 2011 is not necessarily indicative of results that may be expected for the year ending December 31, 2011. The condensed financial statements are unaudited and should be read in conjunction with the audited 2010 financial statements and notes thereto, which are included in KPCo's 2010 Annual Report.

Management reviewed subsequent events through May 3, 2011, the date that the 2011 first quarter report was issued.

Variable Interest Entities

The accounting guidance for "Variable Interest Entities" is a consolidation model that considers if a company has a controlling financial interest in a VIE. A controlling financial interest will have both (a) the power to direct the activities of a VIE that most significantly impact the VIE's economic performance and (b) the obligation to absorb losses of the VIE that could potentially be significant to the VIE or the right to receive benefits from the VIE that could potentially be significant to the VIE. Entities are required to consolidate a VIE when it is determined that they have a controlling financial interest in a VIE and therefore, are the primary beneficiary of that VIE, as defined by the accounting guidance for "Variable Interest Entities." In determining whether KPCo is the primary beneficiary of a VIE, management considers factors such as equity at risk, the amount of the VIE's variability KPCo absorbs, guarantees of indebtedness, voting rights including kick-out rights, the power to direct the VIE and other factors. Management believes that significant assumptions and judgments were applied consistently. There have been no changes to the reporting of VIEs in the financial statements where it is concluded that KPCo is the primary beneficiary. In addition, KPCo has not provided financial or other support to any VIE that was not previously contractually required.

AEPSC provides certain managerial and professional services to AEP's subsidiaries. AEP is the sole equity owner of AEPSC. AEP management controls the activities of AEPSC. The costs of the services are based on a direct charge or on a prorated basis and billed to the AEP subsidiary companies at AEPSC's cost. AEP subsidiaries have not provided financial or other support outside the reimbursement of costs for services rendered. AEPSC finances its operations through cost reimbursement from other AEP subsidiaries. There are no other terms or arrangements between AEPSC and any of the AEP subsidiaries that could require additional financial support from an AEP subsidiary or expose them to losses outside of the normal course of business. AEPSC and its billings are subject to regulation by the FERC. AEP subsidiaries are exposed to losses to the extent they cannot recover the costs of AEPSC through their normal business operations. AEP subsidiaries are considered to have a significant interest in AEPSC due to their activity in AEPSC's cost reimbursement structure. However, AEP subsidiaries do not have control over AEPSC. AEPSC is consolidated by AEP. In the event AEPSC would require financing or other support outside the cost reimbursement billings, this financing would be provided by AEP. KPCo's total billings from AEPSC for the three months ended March 31, 2011 and 2010 were $8 million and $9 million, respectively. The carrying amount of liabilities associated with AEPSC as of March 31, 2011 and December 31, 2010 were $3 million and $3 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

AEGCo, a wholly-owned subsidiary of AEP, is consolidated by AEP. AEGCo owns a 50% ownership interest in Rockport Plant Unit 1 and leases a 50% interest in Rockport Plant Unit 2. AEGCo sells all the output from the Rockport Plant to I&M and KPCo. AEP guarantees all the debt obligations of AEGCo. KPCo is considered to have a significant interest in AEGCo due to its transactions. KPCo is exposed to losses to the extent it cannot recover the costs of AEGCo through its normal business operations. Due to AEP management's control over AEGCo, KPCo is not considered the primary beneficiary of AEGCo. In the event AEGCo would require financing or other support outside the billings to KPCo, this financing would be provided by AEP. Total billings from AEGCo for the three months ended March 31, 2011 and 2010 were $23 million and $24 million, respectively. The carrying amount of liabilities associated with AEGCo as of March 31, 2011 and December 31, 2010 were $7 million and $10 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

Related Party Transactions

AEP Power Pool Purchases from OVEC

In March 2011, the AEP Power Pool began purchasing power from OVEC to serve retail sales through June 2011. These purchases are reported in Purchased Electricity for Resale expenses on KPCo's Condensed Statement of Income. KPCo recorded $519 thousand for the three months ended March 31, 2011.

Adjustments to Benefit Plans Footnote

In Note 4 – Benefit Plans, the disclosure was expanded for KPCo to reflect certain prior period amounts related to the Net Periodic Benefit Cost that were not previously disclosed. These omissions were not material to the financial statements and had no impact on KPCo's previously reported net income, changes in shareholder's equity, financial position or cash flows.

2. RATE MATTERS

As discussed in KPCo's 2010 Annual Report, KPCo is involved in rate and regulatory proceedings at the FERC and the KPSC. The Rate Matters note within KPCo's 2010 Annual Report should be read in conjunction with this report to gain a complete understanding of material rate matters still pending that could impact net income, cash flows and possibly financial condition. The following discusses ratemaking developments in 2011 and updates KPCo's 2010 Annual Report.

FERC Rate Matters

Seams Elimination Cost Allocation (SECA) Revenue Subject to Refund

In 2004, AEP eliminated transaction-based through-and-out transmission service (T&O) charges in accordance with FERC orders and collected, at the FERC's direction, load-based charges, referred to as RTO SECA, to partially mitigate the loss of T&O revenues on a temporary basis through March 2006. Intervenors objected to the temporary SECA rates. The FERC set SECA rate issues for hearing and ordered that the SECA rate revenues be collected, subject to refund. The AEP East companies recognized gross SECA revenues of $220 million from 2004 through 2006 when the SECA rates terminated. KPCo's portion of recognized gross SECA revenues was $17 million.

In 2006, a FERC Administrative Law Judge (ALJ) issued an initial decision finding that the SECA rates charged were unfair, unjust and discriminatory and that new compliance filings and refunds should be made. The ALJ also found that any unpaid SECA rates must be paid in the recommended reduced amount.

AEP filed briefs jointly with other affected companies asking the FERC to reverse the decision. In May 2010, the FERC issued an order that generally supports AEP's position and requires a compliance filing to be filed with the FERC by August 2010. In June 2010, AEP and other affected companies filed a joint request for rehearing with the FERC.

The AEP East companies provided reserves for net refunds for SECA settlements totaling $44 million applicable to the $220 million of SECA revenues collected. KPCo provided a reserve of $3.3 million.

Settlements approved by the FERC consumed $10 million of the reserve for refunds applicable to $112 million of SECA revenue. In December 2010, the FERC issued an order approving a settlement agreement resulting in the collection of $2 million of previously deemed uncollectible SECA revenue. Therefore, the AEP East companies reduced their reserves for net refunds for SECA settlements by $2 million. The balance in the reserve for future settlements as of March 31, 2011 was $32 million. KPCo's portion of the reserve balance as of March 31, 2011 was $2.4 million.

In August 2010, the affected companies, including the AEP East companies, filed a compliance filing with the FERC. If the compliance filing is accepted, the AEP East companies would have to pay refunds of approximately $20 million including estimated interest of $5 million. The AEP East companies could also potentially receive payments up to approximately $10 million including estimated interest of $3 million. KPCo's portion of the potential refund payments and potential payments to be received are $1.5 million and $800 thousand, respectively. A decision is pending from the FERC.

Based on the AEP East companies' analysis of the May 2010 order and the compliance filing, management believes that the reserve is adequate to pay the refunds, including interest, that will be required should the May 2010 order or the compliance filing be made final. Management cannot predict the ultimate outcome of this proceeding at the FERC which could impact future net income and cash flows.

Possible Termination of the Interconnection Agreement

In December 2010, each of the AEP Power Pool members gave notice to AEPSC and each other of their decision to terminate the Interconnection Agreement effective January 2014 or such other date approved by FERC, subject to state regulatory input. No filings have been made at the FERC. It is unknown at this time whether the AEP Power Pool will be replaced by a new agreement among some or all of the members, whether individual companies will enter into bilateral or multi-party contracts with each other for power sales and purchases or asset transfers or if each company will choose to operate independently. This decision to terminate is subject to management's ongoing evaluation. The AEP Power Pool members may revoke their notices of termination. If any of the AEP Power Pool members experience decreases in revenues or increases in costs as a result of the termination of the AEP Power Pool and are unable to recover the change in revenues and costs through rates, prices or additional sales, it could reduce future net income and cash flows.

PJM/MISO Market Flow Calculation Settlement Adjustments

During 2009, an analysis conducted by MISO and PJM discovered several instances of unaccounted for power flows on numerous coordinated flowgates. These flows affected the settlement data for congestion revenues and expenses and dated back to the start of the MISO market in 2005. In January 2011, PJM and MISO reached a settlement agreement where the parties agreed to net various issues to zero. This settlement was filed with the FERC in January 2011. PJM and MISO are currently awaiting final approval from the FERC.

3. COMMITMENTS, GUARANTEES AND CONTINGENCIES

KPCo is subject to certain claims and legal actions arising in its ordinary course of business. In addition, KPCo's business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation cannot be predicted. For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material adverse effect on the financial statements. The Commitments, Guarantees and Contingencies note within the 2010 Annual Report should be read in conjunction with this report.

GUARANTEES

Liabilities for guarantees are recorded in accordance with the accounting guidance for "Guarantees." There is no collateral held in relation to any guarantees. In the event any guarantee is drawn, there is no recourse to third parties.

Indemnifications and Other Guarantees

Contracts

KPCo enters into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. As of March 31, 2011, there are no material liabilities recorded for any indemnifications.

KPCo, along with the other AEP East companies, PSO and SWEPCo, are jointly and severally liable for activity conducted by AEPSC on behalf of the AEP East companies, PSO and SWEPCo related to purchase power and sale activity conducted pursuant to the SIA.

Master Lease Agreements

KPCo leases certain equipment under master lease agreements. In December 2010, management signed a new master lease agreement with GE Capital Commercial Inc. (GE) to replace existing operating and capital leases with GE. These assets were included in existing master lease agreements that were to be terminated in 2011 since GE exercised the termination provision related to these leases in 2008. Certain assets were not included in the refinancing in 2010, but the remaining assets were purchased in January 2011.

For equipment under the GE master lease agreements, the lessor is guaranteed receipt of up to 78% of the unamortized balance of the equipment at the end of the lease term. If the fair value of the leased equipment is below the unamortized balance at the end of the lease term, KPCo is committed to pay the difference between the fair value and the unamortized balance, with the total guarantee not to exceed 78% of the unamortized balance. For equipment under other master lease agreements, the lessor is guaranteed a residual value up to a stated percentage of either the unamortized balance or the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, KPCo is committed to pay the difference between the actual fair value and the residual value guarantee. At March 31, 2011, the maximum potential loss for these lease agreements was approximately $522 thousand assuming the fair value of the equipment is zero at the end of the lease term. Historically, at the end of the lease term the fair value has been in excess of the unamortized balance.

CONTINGENCIES

Carbon Dioxide Public Nuisance Claims

In 2004, eight states and the City of New York filed an action in Federal District Court for the Southern District of New York against AEP, AEPSC, Cinergy Corp, Xcel Energy, Southern Company and Tennessee Valley Authority. The Natural Resources Defense Council, on behalf of three special interest groups, filed a similar complaint against the same defendants. The actions allege that CO_2 emissions from the defendants' power plants constitute a public nuisance under federal common law due to impacts of global warming and sought injunctive relief in the form of specific emission reduction commitments from the defendants. The trial court dismissed the lawsuits.

In September 2009, the Second Circuit Court of Appeals issued a ruling on appeal remanding the cases to the Federal District Court for the Southern District of New York. The Second Circuit held that the issues of climate change and global warming do not raise political questions and that Congress' refusal to regulate CO_2 emissions does not mean that plaintiffs must wait for an initial policy determination by Congress or the President's administration to secure the relief sought in their complaints. The court stated that Congress could enact comprehensive legislation to regulate CO_2 emissions or that the Federal EPA could regulate CO_2 emissions under existing Clean Air Act authorities and that either of these actions could override any decision made by the district court under federal common law. The Second Circuit did not rule on whether the plaintiffs could proceed with their state common law nuisance claims. In December 2010, the defendants' petition for review by the U.S. Supreme Court was granted. The case was heard in April 2011. Management believes the actions are without merit and intends to continue to defend against the claims.

In October 2009, the Fifth Circuit Court of Appeals reversed a decision by the Federal District Court for the District of Mississippi dismissing state common law nuisance claims in a putative class action by Mississippi residents asserting that CO_2 emissions exacerbated the effects of Hurricane Katrina. The Fifth Circuit held that there was no exclusive commitment of the common law issues raised in plaintiffs' complaint to a coordinate branch of government and that no initial policy determination was required to adjudicate these claims. The court granted petitions for rehearing. An additional recusal left the Fifth Circuit without a quorum to reconsider the decision and the appeal was dismissed, leaving the district court's decision in place. Plaintiffs filed a petition with the U.S. Supreme Court asking the court to remand the case to the Fifth Circuit and reinstate the panel decision. The petition was denied in January 2011.

Management is unable to determine a range of potential losses that are reasonably possible of occurring.

Alaskan Villages' Claims

In 2008, the Native Village of Kivalina and the City of Kivalina, Alaska filed a lawsuit in Federal Court in the Northern District of California against AEP, AEPSC and 22 other unrelated defendants including oil and gas companies, a coal company and other electric generating companies. The complaint alleges that the defendants' emissions of CO_2 contribute to global warming and constitute a public and private nuisance and that the defendants are acting together. The complaint further alleges that some of the defendants, including AEP, conspired to create a false scientific debate about global warming in order to deceive the public and perpetuate the alleged nuisance. The plaintiffs also allege that the effects of global warming will require the relocation of the village at an alleged cost of $95 million to $400 million. In October 2009, the judge dismissed plaintiffs' federal common law claim for nuisance, finding the claim barred by the political question doctrine and by plaintiffs' lack of standing to bring the claim. The judge also dismissed plaintiffs' state law claims without prejudice to refiling in state court. The plaintiffs appealed the decision. Briefing is complete and no date has been set for oral argument. The defendants requested that the court defer setting this case for oral argument until after the Supreme Court issues its decision in the CO_2 public nuisance case discussed above. The court entered an order deferring argument until after June 2011. Management believes the action is without merit and intends to defend against the claims. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

4. BENEFIT PLANS

KPCo participates in an AEP sponsored qualified pension plan which covers substantially all of KPCo's employees. KPCo also participates in OPEB plans sponsored by AEP to provide medical and life insurance benefits for retired employees.

Components of Net Periodic Benefit Cost

The following table provides the components of KPCo's net periodic benefit cost for the plans for the three months ended March 31, 2011 and 2010:

	Pension Plan		Other Postretirement Benefit Plans	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2011	2010	2011	2010
	(in thousands)			
Service Cost	$ 347	$ 637	$ 235	$ 265
Interest Cost	1,439	1,475	728	738
Expected Return on Plan Assets	(1,837)	(1,913)	(757)	(710)
Amortization of Transition Obligation	-	-	-	122
Amortization of Prior Service Cost (Credit)	37	37	(9)	-
Amortization of Net Actuarial Loss	738	513	188	183
Net Periodic Benefit Cost	$ 724	$ 749	$ 385	$ 598

5. BUSINESS SEGMENTS

KPCo has one reportable segment, an integrated electricity generation, transmission and distribution business. KPCo's other activities are insignificant.

6. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

KPCo is exposed to certain market risks as a major power producer and marketer of wholesale electricity, coal and emission allowances. These risks include commodity price risk, interest rate risk, credit risk and, to a lesser extent, foreign currency exchange risk. These risks represent the risk of loss that may impact KPCo due to changes in the underlying market prices or rates. AEPSC, on behalf of KPCo, manages these risks using derivative instruments.

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Trading Strategies

The strategy surrounding the use of derivative instruments for trading purposes focuses on seizing market opportunities to create value driven by expected changes in the market prices of the commodities in which AEPSC transacts on behalf of KPCo.

Risk Management Strategies

The strategy surrounding the use of derivative instruments focuses on managing risk exposures, future cash flows and creating value utilizing both economic and formal hedging strategies. To accomplish these objectives, AEPSC, on behalf of KPCo, primarily employs risk management contracts including physical forward purchase and sale contracts, financial forward purchase and sale contracts and financial swap instruments. Not all risk management contracts meet the definition of a derivative under the accounting guidance for "Derivatives and Hedging." Derivative risk management contracts elected normal under the normal purchases and normal sales scope exception are not subject to the requirements of this accounting guidance.

AEPSC, on behalf of KPCo, enters into power, coal, natural gas, interest rate and, to a lesser degree, heating oil and gasoline, emission allowance and other commodity contracts to manage the risk associated with the energy business. AEPSC, on behalf of KPCo, enters into interest rate derivative contracts in order to manage the interest rate exposure associated with KPCo's commodity portfolio. For disclosure purposes, such risks are grouped as "Commodity," as these risks are related to energy risk management activities. AEPSC, on behalf of KPCo, also engages in risk management of interest rate risk associated with debt financing and foreign currency risk associated with future purchase obligations denominated in foreign currencies. The amount of risk taken is determined by the Commercial Operations and Finance groups in accordance with the established risk management policies as approved by the Finance Committee of AEP's Board of Directors.

The following table represents the gross notional volume of the KPCo's outstanding derivative contracts as of March 31, 2011 and December 31, 2010:

Notional Volume of Derivative Instruments

	Volume		
	March 31, 2011	**December 31, 2010**	**Unit of Measure**
	(in thousands)		
Commodity:			
Power	33,395	40,277	MWHs
Coal	3,040	3,280	Tons
Natural Gas	657	449	MMBtus
Heating Oil and Gasoline	298	274	Gallons
Interest Rate	$ 9,059	$ 2,008	USD

Fair Value Hedging Strategies

AEPSC, on behalf of KPCo, enters into interest rate derivative transactions as part of an overall strategy to manage the mix of fixed-rate and floating-rate debt. Certain interest rate derivative transactions effectively modify KPCo's exposure to interest rate risk by converting a portion of KPCo's fixed-rate debt to a floating rate. Provided specific criteria are met, these interest rate derivatives are designated as fair value hedges.

Cash Flow Hedging Strategies

AEPSC, on behalf of KPCo, enters into and designates as cash flow hedges certain derivative transactions for the purchase and sale of power, coal, natural gas and heating oil and gasoline ("Commodity") in order to manage the variable price risk related to the forecasted purchase and sale of these commodities. Management monitors the potential impacts of commodity price changes and, where appropriate, enters into derivative transactions to protect profit margins for a portion of future electricity sales and fuel or energy purchases. KPCo does not hedge all commodity price risk.

KPCo's vehicle fleet is exposed to gasoline and diesel fuel price volatility. AEPSC, on behalf of KPCo, enters into financial heating oil and gasoline derivative contracts in order mitigate price risk of future fuel purchases. For disclosure purposes, these contracts are included with other hedging activity as "Commodity." KPCo does not hedge all fuel price risk.

AEPSC, on behalf of KPCo, enters into a variety of interest rate derivative transactions in order to manage interest rate risk exposure. Some interest rate derivative transactions effectively modify exposure to interest rate risk by converting a portion of floating-rate debt to a fixed rate. AEPSC, on behalf of KPCo, also enters into interest rate derivative contracts to manage interest rate exposure related to anticipated borrowings of fixed-rate debt. The anticipated fixed-rate debt offerings have a high probability of occurrence as the proceeds will be used to fund existing debt maturities and projected capital expenditures. KPCo does not hedge all interest rate exposure.

At times, KPCo is exposed to foreign currency exchange rate risks primarily because some fixed assets are purchased from foreign suppliers. In accordance with AEP's risk management policy, AEPSC, on behalf of KPCo, may enter into foreign currency derivative transactions to protect against the risk of increased cash outflows resulting from a foreign currency's appreciation against the dollar. KPCo does not hedge all foreign currency exposure.

ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND THE IMPACT ON KPCo's FINANCIAL STATEMENTS

The accounting guidance for "Derivatives and Hedging" requires recognition of all qualifying derivative instruments as either assets or liabilities on the balance sheet at fair value. The fair values of derivative instruments accounted for using MTM accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data and assumptions. In order to determine the relevant fair values of the derivative instruments, KPCo applies valuation adjustments for discounting, liquidity and credit quality.

Credit risk is the risk that a counterparty will fail to perform on the contract or fail to pay amounts due. Liquidity risk represents the risk that imperfections in the market will cause the price to vary from estimated fair value based upon prevailing market supply and demand conditions. Since energy markets are imperfect and volatile, there are inherent risks related to the underlying assumptions in models used to fair value risk management contracts. Unforeseen events may cause reasonable price curves to differ from actual price curves throughout a contract's term and at the time a contract settles. Consequently, there could be significant adverse or favorable effects on future net income and cash flows if market prices are not consistent with management's estimates of current market consensus for forward prices in the current period. This is particularly true for longer term contracts. Cash flows may vary based on market conditions, margin requirements and the timing of settlement of KPCo's risk management contracts.

According to the accounting guidance for "Derivatives and Hedging," KPCo reflects the fair values of derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, KPCo is required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the March 31, 2011 and December 31, 2010 balance sheets, KPCo netted $278 thousand and $400 thousand, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and $3.8 million and $3.4 million, respectively, of cash collateral paid to third parties against short-term and long-term risk management liabilities.

The following tables represent the gross fair value impact of KPCo's derivative activity on the Condensed Balance Sheets as of March 31, 2011 and December 31, 2010:

Fair Value of Derivative Instruments
March 31, 2011

	Risk Management Contracts	Hedging Contracts			
Balance Sheet Location	**Commodity (a)**	**Commodity (a)**	**Interest Rate (a)**	**Other (a) (b)**	**Total**
		(in thousands)			
Current Risk Management Assets	$ 49,242	$ 663	$ -	$ (41,644)	$ 8,261
Long-term Risk Management Assets	19,435	146	-	(11,021)	8,560
Total Assets	68,677	809	-	(52,665)	16,821
Current Risk Management Liabilities	48,455	567	-	(44,119)	4,903
Long-term Risk Management Liabilities	15,409	158	-	(12,701)	2,866
Total Liabilities	63,864	725	-	(56,820)	7,769
Total MTM Derivative Contract Net Assets (Liabilities)	$ 4,813	$ 84	$ -	$ 4,155	$ 9,052

Fair Value of Derivative Instruments
December 31, 2010

	Risk Management Contracts	Hedging Contracts			
Balance Sheet Location	**Commodity (a)**	**Commodity (a)**	**Interest Rate (a)**	**Other (a) (b)**	**Total**
		(in thousands)			
Current Risk Management Assets	$ 60,231	$ 418	$ -	$ (51,952)	$ 8,697
Long-term Risk Management Assets	16,978	148	-	(9,096)	8,030
Total Assets	77,209	566	-	(61,048)	16,727
Current Risk Management Liabilities	59,107	490	-	(53,638)	5,959
Long-term Risk Management Liabilities	13,265	146	-	(11,108)	2,303
Total Liabilities	72,372	636	-	(64,746)	8,262
Total MTM Derivative Contract Net Assets (Liabilities)	$ 4,837	$ (70)	$ -	$ 3,698	$ 8,465

(a) Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented on the Condensed Balance Sheets on a net basis in accordance with the accounting guidance for "Derivatives and Hedging."

(b) Amounts include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging." Amounts also include dedesignated risk management contracts.

The table below presents KPCo's activity of derivative risk management contracts for the three months ended March 31, 2011 and 2010:

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Three Months Ended March 31, 2011 and 2010

Location of Gain (Loss)	**2011**	**2010**
	(in thousands)	
Electric Generation, Transmission and Distribution Revenues	$ 2,101	$ 4,635
Sales to AEP Affiliates	3	(742)
Regulatory Assets (a)	93	-
Regulatory Liabilities (a)	(164)	539
Total Gain on Risk Management Contracts	$ 2,033	$ 4,432

(a) Represents realized and unrealized gains and losses subject to regulatory accounting treatment recorded as either current or noncurrent on the balance sheet.

Certain qualifying derivative instruments have been designated as normal purchase or normal sale contracts, as provided in the accounting guidance for "Derivatives and Hedging." Derivative contracts that have been designated as normal purchases or normal sales under that accounting guidance are not subject to MTM accounting treatment and are recognized on the Condensed Statements of Income on an accrual basis.

KPCo's accounting for the changes in the fair value of a derivative instrument depends on whether it qualifies for and has been designated as part of a hedging relationship and further, on the type of hedging relationship. Depending on the exposure, management designates a hedging instrument as a fair value hedge or a cash flow hedge.

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in Revenues on a net basis on KPCo's Condensed Statements of Income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in Revenues or Expenses on KPCo's Condensed Statements of Income depending on the relevant facts and circumstances. However, unrealized and some realized gains and losses for both trading and non-trading derivative instruments are recorded as regulatory assets (for losses) or regulatory liabilities (for gains), in accordance with the accounting guidance for "Regulated Operations."

Accounting for Fair Value Hedging Strategies

For fair value hedges (i.e. hedging the exposure to changes in the fair value of an asset, liability or an identified portion thereof attributable to a particular risk), the gain or loss on the derivative instrument as well as the offsetting gain or loss on the hedged item associated with the hedged risk affects Net Income during the period of change.

KPCo records realized and unrealized gains or losses on interest rate swaps that qualify for fair value hedge accounting treatment and any offsetting changes in the fair value of the debt being hedged in Interest Expense on KPCo's Condensed Statements of Income. During the three months ended March 31, 2011 and 2010, KPCo did not employ any fair value hedging strategies.

Accounting for Cash Flow Hedging Strategies

For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows that is attributable to a particular risk), KPCo initially reports the effective portion of the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income (Loss) on the Condensed Balance Sheets until the period the hedged item affects Net Income. KPCo records hedge ineffectiveness as a regulatory asset (for losses) or a regulatory liability (for gains).

Realized gains and losses on derivatives contracts for the purchase and sale of power, coal, natural gas and heating oil and gasoline designated as cash flow hedges are included in Revenues, Fuel and Other Consumables Used for Electric Generation or Purchased Electricity for Resale on KPCo's Condensed Statements of Income, or in Regulatory Assets or Regulatory Liabilities on KPCo's Condensed Balance Sheets, depending on the specific nature of the risk being hedged. During the three months ended March 31, 2011 and 2010, KPCo designated commodity derivatives as cash flow hedges.

KPCo reclassifies gains and losses on financial fuel derivative contracts designated as cash flow hedges from Accumulated Other Comprehensive Income (Loss) on its Condensed Balance Sheets into Other Operation expense, Maintenance expense or Depreciation and Amortization expense, as it relates to capital projects, on the Condensed Statements of Income. During the three months ended March 31, 2011 and 2010, KPCo designated heating oil and gasoline derivatives as cash flow hedges.

KPCo reclassifies gains and losses on interest rate derivative hedges related to debt financings from Accumulated Other Comprehensive Income (Loss) into Interest Expense in those periods in which hedged interest payments occur. During the three months ended March 31, 2011 and 2010, KPCo did not employ any cash flow hedging strategies for interest rate derivative hedges.

The accumulated gains or losses related to foreign currency hedges are reclassified from Accumulated Other Comprehensive Income (Loss) on KPCo's Condensed Balance Sheets into Depreciation and Amortization expense on the Condensed Statements of Income over the depreciable lives of the fixed assets that were designated as the hedged items in qualifying foreign currency hedging relationships. During the three months ended March 31, 2011 and 2010, KPCo had no foreign currency hedges.

During the three months ended March 31, 2011 and 2010, hedge ineffectiveness was immaterial or nonexistent for all hedge strategies disclosed above.

The following tables provide details on designated, effective cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's Condensed Balance Sheets and the reasons for changes in cash flow hedges for the three months ended March 31, 2011 and 2010. All amounts in the following tables are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
For the Three Months Ended March 31, 2011

	Commodity	Interest Rate	Total
		(in thousands)	
Balance in AOCI as of December 31, 2010	$ (48)	$ (403)	$ (451)
Changes in Fair Value Recognized in AOCI	53	-	53
Amount of (Gain) or Loss Reclassified from AOCI to Income Statement/within Balance Sheet:			
Electric Generation, Transmission and Distribution Revenues	(4)	-	(4)
Purchased Electricity for Resale	87	-	87
Other Operation Expense	(5)	-	(5)
Maintenance Expense	(5)	-	(5)
Interest Expense	-	15	15
Property, Plant and Equipment	(6)	-	(6)
Balance in AOCI as of March 31, 2011	$ 72	$ (388)	$ (316)

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
For the Three Months Ended March 31, 2010

	Commodity	Interest Rate	Total
		(in thousands)	
Balance in AOCI as of December 31, 2009	$ (138)	$ (463)	$ (601)
Changes in Fair Value Recognized in AOCI	(528)	-	(528)
Amount of (Gain) or Loss Reclassified from AOCI to Income Statement/within Balance Sheet:			
Electric Generation, Transmission and Distribution Revenues	25	-	25
Purchased Electricity for Resale	143	-	143
Other Operation Expense	(2)	-	(2)
Maintenance Expense	(3)	-	(3)
Interest Expense	-	15	15
Property, Plant and Equipment	(2)	-	(2)
Balance in AOCI as of March 31, 2010	$ (505)	$ (448)	$ (953)

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's Condensed Balance Sheets at March 31, 2011 and December 31, 2010 were:

Impact of Cash Flow Hedges on the Condensed Balance Sheet
March 31, 2011

	Commodity	Interest Rate	Total
		(in thousands)	
Hedging Assets (a)	$ 230	$ -	$ 230
Hedging Liabilities (a)	(146)	-	(146)
AOCI Loss Net of Tax	72	(388)	(316)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	73	(60)	13

Impact of Cash Flow Hedges on the Condensed Balance Sheet
December 31, 2010

	Commodity	Interest Rate	Total
		(in thousands)	
Hedging Assets (a)	$ 81	$ -	$ 81
Hedging Liabilities (a)	(151)	-	(151)
AOCI Loss Net of Tax	(48)	(403)	(451)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	(48)	(60)	(108)

(a) Hedging Assets and Hedging Liabilities are included in Risk Management Assets and Liabilities on KPCo's Condensed Balance Sheets.

The actual amounts that KPCo reclassifies from Accumulated Other Comprehensive Income (Loss) to Net Income can differ from the estimate above due to market price changes. As of March 31, 2011, the maximum length of time that KPCo is hedging (with contracts subject to the accounting guidance for "Derivatives and Hedging") exposure to variability in future cash flows related to forecasted transactions is 38 months.

Credit Risk

AEPSC, on behalf of KPCo, limits credit risk in KPCo's wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. AEPSC, on behalf of KPCo, uses Moody's, Standard and Poor's and current market-based qualitative and quantitative data as well as financial statements to assess the financial health of counterparties on an ongoing basis.

AEPSC, on behalf of KPCo, uses standardized master agreements which may include collateral requirements. These master agreements facilitate the netting of cash flows associated with a single counterparty. Cash, letters of credit and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. The collateral agreements require a counterparty to post cash or letters of credit in the event an exposure exceeds the established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with AEP's credit policy. In addition, collateral agreements allow for termination and liquidation of all positions in the event of a failure or inability to post collateral.

Collateral Triggering Events

Under the tariffs of the RTOs and Independent System Operators (ISOs) and a limited number of derivative and non-derivative contracts primarily related to competitive retail auction loads, KPCo is obligated to post an additional amount of collateral if certain credit ratings decline below investment grade. The amount of collateral required fluctuates based on market prices and total exposure. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these collateral triggering items in contracts. Management does not anticipate a downgrade below investment grade. The following table represents: (a) the aggregate fair value of such derivative contracts, (b) the amount of collateral KPCo would have been required to post for all derivative and non-derivative contracts if the credit ratings had declined below investment grade and (c) how much was attributable to RTO and ISO activities as of March 31, 2011 and December 31, 2010:

	March 31, 2011	December 31, 2010
	(in thousands)	
Liabilities for Derivative Contracts with Credit Downgrade Triggers	$ 1,309	$ 1,368
Amount of Collateral KPCo Would Have Been Required to Post	3,108	2,614
Amount Attributable to RTO and ISO Activities	3,108	2,608

As of March 31, 2011 and December 31, 2010, KPCo was not required to post any collateral.

In addition, a majority of KPCo's non-exchange traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event by Parent or the obligor under outstanding debt or a third party obligation in excess of $50 million. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-default provisions in the contracts. Management does not anticipate a non-performance event under these provisions. The following table represents: (a) the fair value of these derivative liabilities subject to cross-default provisions prior to consideration of contractual netting arrangements, (b) the amount this exposure has been reduced by cash collateral posted by KPCo and (c) if a cross-default provision would have been triggered, the settlement amount that would be required after considering KPCo's contractual netting arrangements as of March 31, 2011 and December 31, 2010:

	March 31, 2011	December 31, 2010
	(in thousands)	
Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	$ 14,672	$ 15,930
Amount of Cash Collateral Posted	856	1,376
Additional Settlement Liability if Cross Default Provision is Triggered	5,517	4,926

7. FAIR VALUE MEASUREMENTS

Fair Value Hierarchy and Valuation Techniques

The accounting guidance for "Fair Value Measurements and Disclosures" establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. When quoted market prices are not available, pricing may be completed using comparable securities, dealer values, operating data and general market conditions to determine fair value. Valuation models utilize various inputs such as commodity, interest rate and, to a lesser degree, volatility and credit that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability.

For commercial activities, exchange traded derivatives, namely futures contracts, are generally fair valued based on unadjusted quoted prices in active markets and are classified as Level 1. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, as well as exchange traded contracts where there is insufficient market liquidity to warrant inclusion in Level 1. Management verifies price curves using these broker quotes and classifies these fair values within Level 2 when substantially all of the fair value can be corroborated. Management typically obtains multiple broker quotes, which are non-binding in nature but are based on recent trades in the marketplace. When multiple broker quotes are obtained, the quoted bid and ask prices are averaged. In certain circumstances, a broker quote may be discarded if it is a clear outlier. Management uses a historical correlation analysis between the broker quoted location and the illiquid locations. If the points are highly correlated, these locations are included within Level 2 as well. Certain OTC and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. Long-dated and illiquid complex or structured transactions and FTRs can introduce the need for internally developed modeling inputs based upon extrapolations and assumptions of observable market data to estimate fair value. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized as Level 3.

Fair Value Measurements of Long-term Debt

The fair values of Long-term Debt are based on quoted market prices, without credit enhancements, for the same or similar issues and the current interest rates offered for instruments with similar maturities. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that could be realized in a current market exchange.

The book values and fair values of KPCo's Long-term Debt as of March 31, 2011 and December 31, 2010 are summarized in the following table:

	March 31, 2011		December 31, 2010	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
Long-term Debt	$ 548,930	$ 620,309	$ 548,888	$ 628,623

Fair Value Measurements of Financial Assets and Liabilities

The following tables set forth, by level within the fair value hierarchy, KPCo's financial assets and liabilities that were accounted for at fair value on a recurring basis as of March 31, 2011 and December 31, 2010. As required by the accounting guidance for "Fair Value Measurements and Disclosures," financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There have not been any significant changes in management's valuation techniques.

Assets and Liabilities Measured at Fair Value on a Recurring Basis
March 31, 2011

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (c)	$ 278	$ 64,458	$ 2,608	$ (51,414)	$ 15,930
Cash Flow Hedges:					
Commodity Hedges (a)	-	794	-	(564)	230
Dedesignated Risk Management Contracts (b)	-	-	-	661	661
Total Risk Management Assets	$ 278	$ 65,252	$ 2,608	$ (51,317)	$ 16,821
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (c)	$ 272	$ 60,797	$ 1,462	$ (54,908)	$ 7,623
Cash Flow Hedges:					
Commodity Hedges (a)	-	710	-	(564)	146
Total Risk Management Liabilities	$ 272	$ 61,507	$ 1,462	$ (55,472)	$ 7,769

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2010

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (c)	$ 350	$ 73,753	$ 2,862	$ (61,018)	$ 15,947
Cash Flow Hedges:					
Commodity Hedges (a)	-	549	-	(468)	81
Dedesignated Risk Management Contracts (b)	-	-	-	699	699
Total Risk Management Assets	$ 350	$ 74,302	$ 2,862	$ (60,787)	$ 16,727
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (c)	$ 343	$ 69,996	$ 1,789	$ (64,017)	$ 8,111
Cash Flow Hedges:					
Commodity Hedges (a)	-	619	-	(468)	151
Total Risk Management Liabilities	$ 343	$ 70,615	$ 1,789	$ (64,485)	$ 8,262

(a) Amounts in "Other" column primarily represent counterparty netting of risk management and hedging contracts and associated cash collateral under the accounting guidance for "Derivatives and Hedging."

(b) Represents contracts that were originally MTM but were subsequently elected as normal under the accounting guidance for "Derivatives and Hedging." At the time of the normal election, the MTM value was frozen and no longer fair valued. This MTM value will be amortized into revenues over the remaining life of the contracts.

(c) Substantially comprised of power contracts.

There were no transfers between Level 1 and Level 2 during the three months ended March 31, 2011 and 2010.

The following tables set forth a reconciliation of changes in the fair value of net trading derivatives and other investments classified as Level 3 in the fair value hierarchy:

Three Months Ended March 31, 2011		Net Risk Management Assets (Liabilities)
		(in thousands)
Balance as of December 31, 2010	$	1,073
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)		(123)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)		-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income		-
Purchases, Issuances and Settlements (c)		(279)
Transfers into Level 3 (d) (f)		20
Transfers out of Level 3 (e) (f)		(550)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)		1,005
Balance as of March 31, 2011	$	1,146

Three Months Ended March 31, 2010		Net Risk Management Assets (Liabilities)
		(in thousands)
Balance as of December 31, 2009	$	1,899
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)		1,870
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)		-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income		-
Purchases, Issuances and Settlements (c)		(2,130)
Transfers into Level 3 (d) (f)		88
Transfers out of Level 3 (e) (f)		54
Changes in Fair Value Allocated to Regulated Jurisdictions (g)		2,128
Balance as of March 31, 2010	$	3,909

(a) Included in revenues on KPCo's Condensed Statements of Income.
(b) Represents the change in fair value between the beginning of the reporting period and the settlement of the risk management commodity contract.
(c) Represents the settlement of risk management commodity contracts for the reporting period.
(d) Represents existing assets or liabilities that were previously categorized as Level 2.
(e) Represents existing assets or liabilities that were previously categorized as Level 3.
(f) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.
(g) Relates to the net gains (losses) of those contracts that are not reflected on KPCo's Condensed Statements of Income. These net gains (losses) are recorded as regulatory assets/liabilities.

8. INCOME TAXES

KPCo joins in the filing of a consolidated federal income tax return with its affiliates in the AEP System. The allocation of the AEP System's current consolidated federal income tax to the AEP System companies allocates the benefit of current tax losses to the AEP System companies giving rise to such losses in determining their current tax expense. The tax benefit of the Parent is allocated to its subsidiaries with taxable income. With the exception of the loss of the Parent, the method of allocation reflects a separate return result for each company in the consolidated group.

KPCo and other AEP subsidiaries are no longer subject to U.S. federal examination for years before 2001. KPCo and other AEP subsidiaries have completed the exam for the years 2001 through 2006 and have issues that are being pursued at the appeals level. In April 2011, the IRS's examination of the years 2007 and 2008 was concluded with a settlement of all outstanding issues. The settlement will not have a material impact on net income, cash flows or financial condition. Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for federal income taxes have been made for potential liabilities resulting from such matters. In addition, KPCo accrues interest on these uncertain tax positions. Management is not aware of any issues for open tax years that upon final resolution are expected to have a material adverse effect on net income.

KPCo, along with other AEP subsidiaries, files income tax returns in various state and local jurisdictions. These taxing authorities routinely examine the tax returns and KPCo and other AEP subsidiaries are currently under examination in several state and local jurisdictions. Management believes that previously filed tax returns have positions that may be challenged by these tax authorities. However, management believes that adequate provisions for income taxes have been made for potential liabilities resulting from such challenges and that the ultimate resolution of these audits will not materially impact net income. With few exceptions, KPCo is no longer subject to state or local income tax examinations by tax authorities for years before 2000.

Federal Legislation

The Patient Protection and Affordable Care Act and the related Health Care and Education Reconciliation Act (Health Care Acts) were enacted in March 2010. The Health Care Acts amend tax rules so that the portion of employer health care costs that are reimbursed by the Medicare Part D prescription drug subsidy will no longer be deductible by the employer for federal income tax purposes effective for years beginning after December 31, 2012. Because of the loss of the future tax deduction, a reduction in the deferred tax asset related to the nondeductible OPEB liabilities accrued to date was recorded by KPCo in March 2010. This reduction, which was offset by recording net tax regulatory assets, did not materially affect KPCo's net income, cash flows or financial condition.

The Small Business Jobs Act (the Act) was enacted in September 2010. Included in the Act was a one-year extension of the 50% bonus depreciation provision. The Tax Relief, Unemployment Insurance Reauthorization and the Job Creation Act of 2010 extended the life of research and development, employment and several energy tax credits originally scheduled to expire at the end of 2010. In addition, the Act extended the time for claiming bonus depreciation and increased the deduction to 100% for part of 2010 and 2011. The enacted provisions will not have a material impact on KPCo's net income or financial condition.

9. FINANCING ACTIVITIES

Long-term Debt

KPCo did not have any long-term debt issuances or retirements during the first three months of 2011.

Dividend Restrictions

Federal Power Act

The Federal Power Act prohibits KPCo from participating "in the making or paying of any dividends of such public utility from any funds properly included in capital account." The term "capital account" is not defined in the Federal Power Act or its regulations. Management understands "capital account" to mean the par value of the common stock multiplied by the number of shares outstanding. This restriction does not limit the ability of KPCo to pay dividends out of retained earnings.

Leverage Restrictions

Pursuant to credit agreement leverage restrictions, at March 31, 2011, none of the retained earnings of KPCo have restrictions related to the payment of dividends.

Utility Money Pool – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of its subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds the utility subsidiaries. The AEP System Utility Money Pool operates in accordance with the terms and conditions approved in a regulatory order. The amount of outstanding loans to the Utility Money Pool as of March 31, 2011 and December 31, 2010 is included in Advances to Affiliates on KPCo's balance sheets. KPCo's Utility Money Pool activity and corresponding authorized borrowing limits for the three months ended March 31, 2011 are described in the following table:

Maximum Borrowings from Utility Money Pool	Maximum Loans to Utility Money Pool	Average Borrowings from Utility Money Pool	Average Loans to Utility Money Pool	Loans to Utility Money Pool as of March 31, 2011	Authorized Short-Term Borrowing Limit
		(in thousands)			
$ -	$ 101,240	$ -	$ 80,930	$ 93,437	$ 250,000

Maximum, minimum and average interest rates for funds either borrowed from or loaned to the Utility Money Pool for the three months ended March 31, 2011 and 2010 are summarized in the following table:

Year	Maximum Interest Rates for Funds Borrowed from Utility Money Pool	Minimum Interest Rates for Funds Borrowed from Utility Money Pool	Maximum Interest Rates for Funds Loaned to Utility Money Pool	Minimum Interest Rates for Funds Loaned to Utility Money Pool	Average Interest Rates for Funds Borrowed from Utility Money Pool	Average Interest Rates for Funds Loaned to Utility Money Pool
2011	- %	- %	0.56 %	0.06 %	- %	0.31 %
2010	0.34 %	0.09 %	0.17 %	0.09 %	0.17 %	0.13 %

Sale of Receivables – AEP Credit

Under a sale of receivables arrangement, KPCo sells, without recourse, certain of its customer accounts receivable and accrued unbilled revenue balances to AEP Credit and is charged a fee based on AEP Credit's financing costs, administrative costs and uncollectible accounts experience for KPCo's receivables. The costs of customer accounts receivable sold are reported in Other Operation on KPCo's income statement. KPCo manages and services its accounts receivable sold.

In July 2010, AEP Credit renewed its receivables securitization agreement. The agreement provides a commitment of $750 million from bank conduits to purchase receivables. A commitment of $375 million expires in July 2011 and the remaining commitment of $375 million expires in July 2013.

KPCo's amount of accounts receivable and accrued unbilled revenues sold under the sale of receivables agreement was $61million and $63 million as of March 31, 2011 and December 31, 2010, respectively.

The fees paid by KPCo to AEP Credit for customer accounts receivable sold were $608 thousand and $628 thousand for the three months ended March 31, 2011 and 2010, respectively.

KPCo's proceeds on the sale of receivables to AEP Credit were $173 million and $146 million for the three months ended March 31, 2011 and 2010, respectively.

10. COST REDUCTION INITIATIVES

In April 2010, management began initiatives to decrease both labor and non-labor expenses with a goal of achieving significant reductions in operation and maintenance expenses. A total of 2,461 positions were eliminated across the AEP System as a result of process improvements, streamlined organizational designs and other efficiencies. Most of the affected employees terminated employment May 31, 2010. The severance program provided two weeks of base pay for every year of service along with other severance benefits.

KPCo recorded a charge of $11.7 million to Other Operation expense in 2010 primarily related to the headcount reduction initiatives. These costs related primarily to severance benefits. Management does not expect additional costs to be incurred related to this initiative.

Balance at December 31, 2010	Incurred	Settled (in thousands)	Adjustments	Balance at March 31, 2011
$ 1,018	$ -	$ (251)	$ (78)	$ 689

The remaining accrual is included in Other Current Liabilities on the Condensed Balance Sheets.

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Kentucky Power Company

2011 Second Quarter Report

Financial Statements

AMERICAN ELECTRIC POWER

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GLOSSARY OF TERMS

When the following terms and abbreviations appear in the text of this report, they have the meanings indicated below.

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP or Parent	American Electric Power Company, Inc., a holding company.
AEP Credit	AEP Credit, Inc., a subsidiary of AEP which factors accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP East companies	APCo, CSPCo, I&M, KPCo and OPCo.
AEP Power Pool	Members are APCo, CSPCo, I&M, KPCo and OPCo. The Pool shares the generation, cost of generation and resultant wholesale off-system sales of the member companies.
AEP System or the System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEPSC	American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
ASU	Accounting Standard Update.
CAA	Clean Air Act.
CO_2	Carbon Dioxide and other greenhouse gases.
CSPCo	Columbus Southern Power Company, an AEP electric utility subsidiary.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
GAAP	Accounting Principles Generally Accepted in the United States of America.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
MISO	Midwest Independent Transmission System Operator.
MMBtu	Million British Thermal Units.
MTM	Mark-to-Market.
MW	Megawatt.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefit Plans.
OTC	Over the counter.
PJM	Pennsylvania – New Jersey – Maryland, a RTO.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generating plant, consisting of two 1,300 MW coal-fired generating units near Rockport, Indiana.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
SIA	System Integration Agreement, effective June 15, 2000, provides contractual basis for coordinated planning, operation and maintenance of the power supply sources of the combined AEP.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.

Term	Meaning
Utility Money Pool	AEP System's Utility Money Pool is the centralized funding mechanism AEP uses to meet the short term cash requirements of pool participants.
VIE	Variable Interest Entity.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF OPERATIONS
For the Three and Six Months Ended June 30, 2011 and 2010
(in thousands)
(Unaudited)

	Three Months Ended		Six Months Ended	
	2011	2010	2011	2010
REVENUES				
Electric Generation, Transmission and Distribution	$ 155,023	$ 127,349	$ 334,114	$ 289,845
Sales to AEP Affiliates	19,520	9,613	36,435	20,945
Other Revenues	131	10	243	100
TOTAL REVENUES	174,674	136,972	370,792	310,890
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	53,790	33,803	116,625	86,725
Purchased Electricity for Resale	6,583	4,467	11,585	9,337
Purchased Electricity from AEP Affiliates	52,818	50,727	103,288	102,724
Other Operation	15,194	23,255	31,309	38,340
Maintenance	15,339	10,956	26,336	19,171
Depreciation and Amortization	13,474	13,163	26,860	26,258
Taxes Other Than Income Taxes	2,914	3,432	4,950	6,486
TOTAL EXPENSES	160,112	139,803	320,953	289,041
OPERATING INCOME (LOSS)	14,562	(2,831)	49,839	21,849
Other Income (Expense):				
Interest Income	106	57	212	102
Allowance for Equity Funds Used During Construction	278	225	513	442
Interest Expense	(9,174)	(9,173)	(18,373)	(18,312)
INCOME (LOSS) BEFORE INCOME TAX EXPENSE (CREDIT)	5,772	(11,722)	32,191	4,081
Income Tax Expense (Credit)	2,300	(4,677)	11,849	1,635
NET INCOME (LOSS)	$ 3,472	$ (7,045)	$ 20,342	$ 2,446

The common stock of KPCo is wholly-owned by AEP.

See Condensed Notes to Condensed Financial Statements.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Six Months Ended June 30, 2011 and 2010
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2009	$ 50,450	$ 238,750	$ 143,185	$ (601)	$ 431,784
Common Stock Dividends			(10,000)		(10,000)
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					421,784
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $72				(133)	(133)
NET INCOME			2,446		2,446
TOTAL COMPREHENSIVE INCOME					2,313
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2010	$ 50,450	$ 238,750	$ 135,631	$ (734)	$ 424,097
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2010	$ 50,450	$ 238,750	$ 157,467	$ (451)	$ 446,216
Common Stock Dividends			(10,000)		(10,000)
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					436,216
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $124				231	231
NET INCOME			20,342		20,342
TOTAL COMPREHENSIVE INCOME					20,573
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2011	$ 50,450	$ 238,750	$ 167,809	$ (220)	$ 456,789

See Condensed Notes to Condensed Financial Statements.

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
ASSETS
June 30, 2011 and December 31, 2010
(in thousands)
(Unaudited)

	2011	2010
CURRENT ASSETS		
Cash and Cash Equivalents	$ 596	$ 281
Advances to Affiliates	85,653	67,060
Accounts Receivable:		
Customers	16,631	21,652
Affiliated Companies	17,818	17,616
Accrued Unbilled Revenues	62	3,823
Miscellaneous	424	587
Allowance for Uncollectible Accounts	(662)	(623)
Total Accounts Receivable	34,273	43,055
Fuel	18,744	16,640
Materials and Supplies	13,289	24,378
Risk Management Assets	6,785	8,697
Accrued Tax Benefits	-	1,420
Margin Deposits	4,827	5,357
Prepayments and Other Current Assets	1,723	1,497
TOTAL CURRENT ASSETS	165,890	168,385
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	555,197	553,589
Transmission	453,421	444,303
Distribution	600,501	590,606
Other Property, Plant and Equipment	64,075	63,982
Construction Work in Progress	30,828	34,093
Total Property, Plant and Equipment	1,704,022	1,686,573
Accumulated Depreciation and Amortization	560,898	542,443
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	1,143,124	1,144,130
OTHER NONCURRENT ASSETS		
Regulatory Assets	207,048	213,593
Long-term Risk Management Assets	6,853	8,030
Deferred Charges and Other Noncurrent Assets	38,561	37,946
TOTAL OTHER NONCURRENT ASSETS	252,462	259,569
TOTAL ASSETS	$ 1,561,476	$ 1,572,084

See Condensed Notes to Condensed Financial Statements.

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
LIABILITIES AND SHAREHOLDER'S EQUITY
June 30, 2011 and December 31, 2010
(Unaudited)

	2011	2010
	(in thousands)	
CURRENT LIABILITIES		
Accounts Payable:		
General	$ 25,930	$ 33,334
Affiliated Companies	31,298	45,790
Risk Management Liabilities	3,997	5,959
Customer Deposits	20,964	19,692
Accrued Taxes	25,960	23,741
Accrued Interest	7,132	7,570
Other Current Liabilities	20,007	26,227
TOTAL CURRENT LIABILITIES	135,288	162,313
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	528,972	528,888
Long-term Debt – Affiliated	20,000	20,000
Long-term Risk Management Liabilities	2,213	2,303
Deferred Income Taxes	323,737	316,389
Regulatory Liabilities and Deferred Investment Tax Credits	37,012	34,991
Employee Benefits and Pension Obligations	46,350	49,298
Deferred Credits and Other Noncurrent Liabilities	11,115	11,686
TOTAL NONCURRENT LIABILITIES	969,399	963,555
TOTAL LIABILITIES	1,104,687	1,125,868
Rate Matters (Note 3)		
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $50 Per Share:		
Authorized – 2,000,000 Shares		
Outstanding – 1,009,000 Shares	50,450	50,450
Paid-in Capital	238,750	238,750
Retained Earnings	167,809	157,467
Accumulated Other Comprehensive Income (Loss)	(220)	(451)
TOTAL COMMON SHAREHOLDER'S EQUITY	456,789	446,216
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$ 1,561,476	$ 1,572,084

See Condensed Notes to Condensed Financial Statements.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2011 and 2010
(in thousands)
(Unaudited)

	2011	2010
OPERATING ACTIVITIES		
Net Income	$ 20,342	$ 2,446
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	26,860	26,258
Deferred Income Taxes	4,668	2,948
Allowance for Equity Funds Used During Construction	(513)	(442)
Mark-to-Market of Risk Management Contracts	1,369	1,480
Property Taxes	3,709	4,749
Fuel Over/Under-Recovery, Net	67	(380)
Change in Other Noncurrent Assets	17	869
Change in Other Noncurrent Liabilities	2,068	(984)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	8,809	3,780
Fuel, Materials and Supplies	8,985	13,059
Accounts Payable	(20,183)	(22,918)
Customer Deposits	1,272	838
Accrued Taxes, Net	2,201	(6,295)
Other Current Assets	278	531
Other Current Liabilities	(2,578)	3,455
Net Cash Flows from Operating Activities	57,371	29,394
INVESTING ACTIVITIES		
Construction Expenditures	(27,987)	(22,652)
Change in Advances to Affiliates, Net	(18,593)	-
Acquisitions of Assets	(8)	(201)
Proceeds from Sales of Assets	301	506
Net Cash Flows Used for Investing Activities	(46,287)	(22,347)
FINANCING ACTIVITIES		
Change in Advances from Affiliates, Net	-	3,783
Principal Payments for Capital Lease Obligations	(769)	(875)
Dividends Paid on Common Stock	(10,000)	(10,000)
Other Financing Activities	-	1
Net Cash Flows Used for Financing Activities	(10,769)	(7,091)
Net Increase (Decrease) in Cash and Cash Equivalents	315	(44)
Cash and Cash Equivalents at Beginning of Period	281	494
Cash and Cash Equivalents at End of Period	$ 596	$ 450
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 18,376	$ 18,479
Net Cash Paid for Income Taxes	446	5,091
Noncash Acquisitions Under Capital Leases	8	4,177
Construction Expenditures Included in Current Liabilities at June 30,	3,271	2,134

See Condensed Notes to Condensed Financial Statements.

INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS

1. SIGNIFICANT ACCOUNTING MATTERS

General

The unaudited condensed financial statements and footnotes were prepared in accordance with GAAP for interim financial information. Accordingly, they do not include all of the information and footnotes required by GAAP for complete annual financial statements.

In the opinion of management, the unaudited condensed interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair presentation of the net income, financial position and cash flows for the interim periods. Net income for the three and six months ended June 30, 2011 is not necessarily indicative of results that may be expected for the year ending December 31, 2011. The condensed financial statements are unaudited and should be read in conjunction with the audited 2010 financial statements and notes thereto, which are included in KPCo's 2010 Annual Report.

Management reviewed subsequent events through July 29, 2011, the date that the second quarter 2011 report was issued.

Variable Interest Entities

The accounting guidance for "Variable Interest Entities" is a consolidation model that considers if a company has a controlling financial interest in a VIE. A controlling financial interest will have both (a) the power to direct the activities of a VIE that most significantly impact the VIE's economic performance and (b) the obligation to absorb losses of the VIE that could potentially be significant to the VIE or the right to receive benefits from the VIE that could potentially be significant to the VIE. Entities are required to consolidate a VIE when it is determined that they have a controlling financial interest in a VIE and therefore, are the primary beneficiary of that VIE, as defined by the accounting guidance for "Variable Interest Entities." In determining whether KPCo is the primary beneficiary of a VIE, management considers factors such as equity at risk, the amount of the VIE's variability KPCo absorbs, guarantees of indebtedness, voting rights including kick-out rights, the power to direct the VIE and other factors. Management believes that significant assumptions and judgments were applied consistently. There have been no changes to the reporting of VIEs in the financial statements where it is concluded that KPCo is the primary beneficiary. In addition, KPCo has not provided financial or other support to any VIE that was not previously contractually required.

AEPSC provides certain managerial and professional services to AEP's subsidiaries. AEP is the sole equity owner of AEPSC. AEP management controls the activities of AEPSC. The costs of the services are based on a direct charge or on a prorated basis and billed to the AEP subsidiary companies at AEPSC's cost. AEP subsidiaries have not provided financial or other support outside the reimbursement of costs for services rendered. AEPSC finances its operations through cost reimbursement from other AEP subsidiaries. There are no other terms or arrangements between AEPSC and any of the AEP subsidiaries that could require additional financial support from an AEP subsidiary or expose them to losses outside of the normal course of business. AEPSC and its billings are subject to regulation by the FERC. AEP subsidiaries are exposed to losses to the extent they cannot recover the costs of AEPSC through their normal business operations. AEP subsidiaries are considered to have a significant interest in AEPSC due to their activity in AEPSC's cost reimbursement structure. However, AEP subsidiaries do not have control over AEPSC. AEPSC is consolidated by AEP. In the event AEPSC would require financing or other support outside the cost reimbursement billings, this financing would be provided by AEP. KPCo's total billings from AEPSC for the three months ended June 30, 2011 and 2010 were $8 million and $11 million, respectively, and for the six months ended June 30, 2011 and 2010 were $16 million and $20 million, respectively. The carrying amount of liabilities associated with AEPSC as of June 30, 2011 and December 31, 2010 were $3 million and $3 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

AEGCo, a wholly-owned subsidiary of AEP, is consolidated by AEP. AEGCo owns a 50% ownership interest in Rockport Plant Unit 1 and leases a 50% interest in Rockport Plant Unit 2. AEGCo sells all the output from the Rockport Plant to I&M and KPCo. AEP guarantees all the debt obligations of AEGCo. KPCo is considered to have a significant interest in AEGCo due to its transactions. KPCo is exposed to losses to the extent it cannot recover the costs of AEGCo through its normal business operations. Due to AEP management's control over AEGCo, KPCo is not considered the primary beneficiary of AEGCo. In the event AEGCo would require financing or other support outside the billings to KPCo, this financing would be provided by AEP. Total billings from AEGCo for the three months ended June 30, 2011 and 2010 were $21 million and $21 million, respectively and for the six months ended June 30, 2011 and 2010 were $44 million and $45 million, respectively. The carrying amount of liabilities associated with AEGCo as of June 30, 2011 and December 31, 2010 were $8 million and $10 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

2. NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of final pronouncements, management reviews the new accounting literature to determine its relevance, if any, to KPCo's business. The following represents a summary of final pronouncements that impact the financial statements.

Pronouncements Issued During 2011

The following standard was issued during the first six months of 2011. The following paragraphs discuss its impact on future financial statements.

ASU 2011-05 "Presentation of Comprehensive Income" (ASU 2011-05)

In June 2011, the FASB issued ASU 2011-05 eliminating the option to present the components of other comprehensive income as a part of the statement of shareholders' equity. The standard requires other comprehensive income be presented as part of a single continuous statement of comprehensive income or in a statement of other comprehensive income immediately following the statement of net income. Reclassification adjustments from other comprehensive income to net income must be presented on the face of the financial statements. This standard must be retrospectively applied to all reporting periods presented in financial reports issued after the effective date.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2011. This standard will change the presentation of the financial statements but will not affect the calculation of net income or comprehensive income. KPCo will adopt ASU 2011-05 effective January 1, 2012.

3. RATE MATTERS

As discussed in KPCo's 2010 Annual Report, KPCo is involved in rate and regulatory proceedings at the FERC and the KPSC. The Rate Matters note within KPCo's 2010 Annual Report should be read in conjunction with this report to gain a complete understanding of material rate matters still pending that could impact net income, cash flows and possibly financial condition. The following discusses ratemaking developments in 2011 and updates KPCo's 2010 Annual Report.

FERC Rate Matters

Seams Elimination Cost Allocation (SECA) Revenue Subject to Refund

In 2004, AEP eliminated transaction-based through-and-out transmission service (T&O) charges in accordance with FERC orders and collected, at the FERC's direction, load-based charges, referred to as RTO SECA, to partially mitigate the loss of T&O revenues on a temporary basis through March 2006. Intervenors objected to the temporary SECA rates. The FERC set SECA rate issues for hearing and ordered that the SECA rate revenues be collected, subject to refund. The AEP East companies recognized gross SECA revenues of $220 million from 2004 through 2006 when the SECA rates terminated. KPCo's portion of recognized gross SECA revenues was $17 million.

In 2006, a FERC Administrative Law Judge (ALJ) issued an initial decision finding that the SECA rates charged were unfair, unjust and discriminatory and that new compliance filings and refunds should be made. The ALJ also found that any unpaid SECA rates must be paid in the recommended reduced amount.

AEP filed briefs jointly with other affected companies asking the FERC to reverse the decision. In May 2010, the FERC issued an order that generally supports AEP's position and requires a compliance filing to be filed with the FERC by August 2010. In June 2010, AEP and other affected companies filed a joint request for rehearing with the FERC.

The AEP East companies provided reserves for net refunds for SECA settlements totaling $44 million applicable to the $220 million of SECA revenues collected. KPCo provided a reserve of $3.3 million.

Settlements approved by the FERC consumed $10 million of the reserve for refunds applicable to $112 million of SECA revenue. In December 2010, the FERC issued an order approving a settlement agreement resulting in the collection of $2 million of previously deemed uncollectible SECA revenue. Therefore, the AEP East companies reduced their reserves for net refunds for SECA settlements by $2 million. The balance in the reserve for future settlements as of June 30, 2011 was $32 million. KPCo's portion of the reserve balance as of June 30, 2011 was $2.4 million.

In August 2010, the affected companies, including the AEP East companies, filed a compliance filing with the FERC. If the compliance filing is accepted, the AEP East companies would have to pay refunds of approximately $20 million including estimated interest of $5 million. The AEP East companies could also potentially receive payments up to approximately $10 million including estimated interest of $3 million. KPCo's portion of the potential refund payments and potential payments to be received are $1.5 million and $800 thousand, respectively. A decision is pending from the FERC.

Based on the AEP East companies' analysis of the May 2010 order and the compliance filing, management believes that the reserve is adequate to pay the refunds, including interest, that will be required should the May 2010 order or the compliance filing be made final. Management cannot predict the ultimate outcome of this proceeding at the FERC which could impact future net income and cash flows.

Possible Termination of the Interconnection Agreement

In December 2010, each of the AEP Power Pool members gave notice to AEPSC and each other of their decision to terminate the Interconnection Agreement effective January 2014 or such other date approved by FERC, subject to state regulatory input. No filings have been made at the FERC. It is unknown at this time whether the AEP Power Pool will be replaced by a new agreement among some or all of the members, whether individual companies will enter into bilateral or multi-party contracts with each other for power sales and purchases or asset transfers or if each company will choose to operate independently. This decision to terminate is subject to management's ongoing evaluation. The AEP Power Pool members may revoke their notices of termination. If any of the AEP Power Pool members experience decreases in revenues or increases in costs as a result of the termination of the AEP Power Pool and are unable to recover the change in revenues and costs through rates, prices or additional sales, it could reduce future net income and cash flows.

PJM/MISO Market Flow Calculation Settlement Adjustments

During 2009, an analysis conducted by MISO and PJM discovered several instances of unaccounted for power flows on numerous coordinated flowgates. These flows affected the settlement data for congestion revenues and expenses and dated back to the start of the MISO market in 2005. In January 2011, PJM and MISO reached a settlement agreement where the parties agreed to net various issues to zero. In June 2011, the FERC approved the settlement agreement.

4. COMMITMENTS, GUARANTEES AND CONTINGENCIES

KPCo is subject to certain claims and legal actions arising in its ordinary course of business. In addition, KPCo's business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation cannot be predicted. For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material adverse effect on the financial statements. The Commitments, Guarantees and Contingencies note within KPCo's 2010 Annual Report should be read in conjunction with this report.

GUARANTEES

Liabilities for guarantees are recorded in accordance with the accounting guidance for "Guarantees." There is no collateral held in relation to any guarantees. In the event any guarantee is drawn, there is no recourse to third parties.

Indemnifications and Other Guarantees

Contracts

KPCo enters into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. As of June 30, 2011, there were no material liabilities recorded for any indemnifications.

KPCo, along with the other AEP East companies, PSO and SWEPCo, are jointly and severally liable for activity conducted by AEPSC on behalf of the AEP East companies, PSO and SWEPCo related to purchase power and sale activity conducted pursuant to the SIA.

Master Lease Agreements

KPCo leases certain equipment under master lease agreements. In December 2010, management signed a new master lease agreement with GE Capital Commercial Inc. (GE) to replace existing operating and capital leases with GE. These assets were included in existing master lease agreements that were to be terminated in 2011 since GE exercised the termination provision related to these leases in 2008. Certain previously leased assets were not included in the 2010 refinancing, but were purchased in January 2011.

For equipment under the GE master lease agreements, the lessor is guaranteed receipt of up to 78% of the unamortized balance of the equipment at the end of the lease term. If the fair value of the leased equipment is below the unamortized balance at the end of the lease term, KPCo is committed to pay the difference between the fair value and the unamortized balance, with the total guarantee not to exceed 78% of the unamortized balance. For equipment under other master lease agreements, the lessor is guaranteed a residual value up to a stated percentage of either the unamortized balance or the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, KPCo is committed to pay the difference between the actual fair value and the residual value guarantee. At June 30, 2011, the maximum potential loss for these lease agreements was approximately $560 thousand assuming the fair value of the equipment is zero at the end of the lease term. Historically, at the end of the lease term the fair value has been in excess of the unamortized balance.

CONTINGENCIES

Carbon Dioxide Public Nuisance Claims

In 2004, eight states and the City of New York filed an action in Federal District Court for the Southern District of New York against AEP, AEPSC, Cinergy Corp, Xcel Energy, Southern Company and Tennessee Valley Authority. The Natural Resources Defense Council, on behalf of three special interest groups, filed a similar complaint against the same defendants. The actions allege that CO_2 emissions from the defendants' power plants constitute a public nuisance under federal common law due to impacts of global warming and sought injunctive relief in the form of specific emission reduction commitments from the defendants. The trial court dismissed the lawsuits.

In September 2009, the Second Circuit Court of Appeals issued a ruling on appeal remanding the cases to the Federal District Court for the Southern District of New York. The Second Circuit held that the issues of climate change and global warming do not raise political questions and that Congress' refusal to regulate CO_2 emissions does not mean that plaintiffs must wait for an initial policy determination by Congress or the President's administration to secure the relief sought in their complaints. The court stated that Congress could enact comprehensive legislation to regulate CO_2 emissions or that the Federal EPA could regulate CO_2 emissions under existing CAA authorities and that either of these actions could override any decision made by the district court under federal common law. The Second Circuit did not rule on whether the plaintiffs could proceed with their state common law nuisance claims. In 2010, the U.S. Supreme Court granted the defendants' petition for review. In June 2011, the U.S. Supreme Court reversed and remanded the case to the Court of Appeals, finding that plaintiffs' federal common law claims are displaced by the regulatory authority granted to the Federal EPA under the CAA.

In October 2009, the Fifth Circuit Court of Appeals reversed a decision by the Federal District Court for the District of Mississippi dismissing state common law nuisance claims in a putative class action by Mississippi residents asserting that CO_2 emissions exacerbated the effects of Hurricane Katrina. The Fifth Circuit held that there was no exclusive commitment of the common law issues raised in plaintiffs' complaint to a coordinate branch of government and that no initial policy determination was required to adjudicate these claims. The court granted petitions for rehearing. An additional recusal left the Fifth Circuit without a quorum to reconsider the decision and the appeal was dismissed, leaving the district court's decision in place. Plaintiffs filed a petition with the U.S. Supreme Court asking the court to remand the case to the Fifth Circuit and reinstate the panel decision. The petition was denied in January 2011. Plaintiffs refiled their complaint in federal district court. Management believes the claims are without merit, and in addition to other defenses, are barred by the doctrine of collateral estoppel and the applicable statute of limitations. Management intends to vigorously defend against the claims. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

Alaskan Villages' Claims

In 2008, the Native Village of Kivalina and the City of Kivalina, Alaska filed a lawsuit in Federal Court in the Northern District of California against AEP, AEPSC and 22 other unrelated defendants including oil and gas companies, a coal company and other electric generating companies. The complaint alleges that the defendants' emissions of CO_2 contribute to global warming and constitute a public and private nuisance and that the defendants are acting together. The complaint further alleges that some of the defendants, including AEP, conspired to create a false scientific debate about global warming in order to deceive the public and perpetuate the alleged nuisance. The plaintiffs also allege that the effects of global warming will require the relocation of the village at an alleged cost of \$95 million to \$400 million. In October 2009, the judge dismissed plaintiffs' federal common law claim for nuisance, finding the claim barred by the political question doctrine and by plaintiffs' lack of standing to bring the claim. The judge also dismissed plaintiffs' state law claims without prejudice to refiling in state court. The plaintiffs appealed the decision. Briefing is complete and no date has been set for oral argument. The defendants requested that the court defer setting this case for oral argument until after the Supreme Court issues its decision in the CO_2 public nuisance case discussed above. The court entered an order deferring argument until after June 2011 and the parties requested supplemental briefing on the impact of the Supreme Court's decision. Management believes the action is without merit and intends to defend against the claims. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

5. BENEFIT PLANS

KPCo participates in an AEP sponsored qualified pension plan which covers substantially all of KPCo's employees. KPCo also participates in OPEB plans sponsored by AEP to provide medical and life insurance benefits for retired employees.

Components of Net Periodic Benefit Cost

The following tables provide the components of KPCo's net periodic benefit cost for the plans for the three and six months ended June 30, 2011 and 2010:

	Pension Plan		Other Postretirement Benefit Plans	
	Three Months Ended June 30,		Three Months Ended June 30,	
	2011	2010	2011	2010
	(in thousands)			
Service Cost	$ 347	$ 637	$ 235	$ 265
Interest Cost	1,439	1,475	729	738
Expected Return on Plan Assets	(1,838)	(1,914)	(758)	(710)
Amortization of Transition Obligation	-	-	-	122
Amortization of Prior Service Cost (Credit)	38	38	(8)	-
Amortization of Net Actuarial Loss	738	513	187	183
Net Periodic Benefit Cost	$ 724	$ 749	$ 385	$ 598

	Pension Plan		Other Postretirement Benefit Plans	
	Six Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(in thousands)			
Service Cost	$ 694	$ 1,274	$ 470	$ 530
Interest Cost	2,878	2,950	1,457	1,476
Expected Return on Plan Assets	(3,675)	(3,827)	(1,515)	(1,420)
Amortization of Transition Obligation	-	-	-	244
Amortization of Prior Service Cost (Credit)	75	75	(17)	-
Amortization of Net Actuarial Loss	1,476	1,026	375	366
Net Periodic Benefit Cost	$ 1,448	$ 1,498	$ 770	$ 1,196

6. BUSINESS SEGMENTS

KPCo has one reportable segment, an integrated electricity generation, transmission and distribution business. KPCo's other activities are insignificant.

7. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

KPCo is exposed to certain market risks as a major power producer and marketer of wholesale electricity, coal and emission allowances. These risks include commodity price risk, interest rate risk, credit risk and, to a lesser extent, foreign currency exchange risk. These risks represent the risk of loss that may impact KPCo due to changes in the underlying market prices or rates. AEPSC, on behalf of KPCo, manages these risks using derivative instruments.

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Trading Strategies

The strategy surrounding the use of derivative instruments for trading purposes focuses on seizing market opportunities to create value driven by expected changes in the market prices of the commodities in which AEPSC transacts on behalf of KPCo.

Risk Management Strategies

The strategy surrounding the use of derivative instruments focuses on managing risk exposures, future cash flows and creating value utilizing both economic and formal hedging strategies. To accomplish these objectives, AEPSC, on behalf of KPCo, primarily employs risk management contracts including physical forward purchase and sale contracts, financial forward purchase and sale contracts and financial swap instruments. Not all risk management contracts meet the definition of a derivative under the accounting guidance for "Derivatives and Hedging." Derivative risk management contracts elected normal under the normal purchases and normal sales scope exception are not subject to the requirements of this accounting guidance.

AEPSC, on behalf of KPCo, enters into power, coal, natural gas, interest rate and, to a lesser degree, heating oil and gasoline, emission allowance and other commodity contracts to manage the risk associated with the energy business. AEPSC, on behalf of KPCo, enters into interest rate derivative contracts in order to manage the interest rate exposure associated with KPCo's commodity portfolio. For disclosure purposes, such risks are grouped as "Commodity," as these risks are related to energy risk management activities. AEPSC, on behalf of KPCo, also engages in risk management of interest rate risk associated with debt financing and foreign currency risk associated with future purchase obligations denominated in foreign currencies. The amount of risk taken is determined by the Commercial Operations and Finance groups in accordance with the established risk management policies as approved by the Finance Committee of AEP's Board of Directors.

The following table represents the gross notional volume of the KPCo's outstanding derivative contracts as of June 30, 2011 and December 31, 2010:

Notional Volume of Derivative Instruments

	Volume (in thousands) June 30, 2011	Volume (in thousands) December 31, 2010	Unit of Measure
Commodity:			
Power	56,183	40,277	MWHs
Coal	2,618	3,280	Tons
Natural Gas	579	449	MMBtus
Heating Oil and Gasoline	323	274	Gallons
Interest Rate	$ 8,901	$ 2,008	USD

Fair Value Hedging Strategies

AEPSC, on behalf of KPCo, enters into interest rate derivative transactions as part of an overall strategy to manage the mix of fixed-rate and floating-rate debt. Certain interest rate derivative transactions effectively modify KPCo's exposure to interest rate risk by converting a portion of KPCo's fixed-rate debt to a floating rate. Provided specific criteria are met, these interest rate derivatives are designated as fair value hedges.

Cash Flow Hedging Strategies

AEPSC, on behalf of KPCo, enters into and designates as cash flow hedges certain derivative transactions for the purchase and sale of power, coal, natural gas and heating oil and gasoline ("Commodity") in order to manage the variable price risk related to the forecasted purchase and sale of these commodities. Management monitors the potential impacts of commodity price changes and, where appropriate, enters into derivative transactions to protect profit margins for a portion of future electricity sales and fuel or energy purchases. KPCo does not hedge all commodity price risk.

KPCo's vehicle fleet is exposed to gasoline and diesel fuel price volatility. AEPSC, on behalf of KPCo, enters into financial heating oil and gasoline derivative contracts in order mitigate price risk of future fuel purchases. For disclosure purposes, these contracts are included with other hedging activity as "Commodity." KPCo does not hedge all fuel price risk.

AEPSC, on behalf of KPCo, enters into a variety of interest rate derivative transactions in order to manage interest rate risk exposure. Some interest rate derivative transactions effectively modify exposure to interest rate risk by converting a portion of floating-rate debt to a fixed rate. AEPSC, on behalf of KPCo, also enters into interest rate derivative contracts to manage interest rate exposure related to anticipated borrowings of fixed-rate debt. The anticipated fixed-rate debt offerings have a high probability of occurrence as the proceeds will be used to fund existing debt maturities and projected capital expenditures. KPCo does not hedge all interest rate exposure.

At times, KPCo is exposed to foreign currency exchange rate risks primarily because some fixed assets are purchased from foreign suppliers. In accordance with AEP's risk management policy, AEPSC, on behalf of KPCo, may enter into foreign currency derivative transactions to protect against the risk of increased cash outflows resulting from a foreign currency's appreciation against the dollar. KPCo does not hedge all foreign currency exposure.

ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND THE IMPACT ON KPCo's FINANCIAL STATEMENTS

The accounting guidance for "Derivatives and Hedging" requires recognition of all qualifying derivative instruments as either assets or liabilities on the balance sheet at fair value. The fair values of derivative instruments accounted for using MTM accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data and assumptions. In order to determine the relevant fair values of the derivative instruments, KPCo applies valuation adjustments for discounting, liquidity and credit quality.

Credit risk is the risk that a counterparty will fail to perform on the contract or fail to pay amounts due. Liquidity risk represents the risk that imperfections in the market will cause the price to vary from estimated fair value based upon prevailing market supply and demand conditions. Since energy markets are imperfect and volatile, there are inherent risks related to the underlying assumptions in models used to fair value risk management contracts. Unforeseen events may cause reasonable price curves to differ from actual price curves throughout a contract's term and at the time a contract settles. Consequently, there could be significant adverse or favorable effects on future net income and cash flows if market prices are not consistent with management's estimates of current market consensus for forward prices in the current period. This is particularly true for longer term contracts. Cash flows may vary based on market conditions, margin requirements and the timing of settlement of KPCo's risk management contracts.

According to the accounting guidance for "Derivatives and Hedging," KPCo reflects the fair values of derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, KPCo is required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the June 30, 2011 and December 31, 2010 balance sheets, KPCo netted $598 thousand and $400 thousand, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and $2.2 million and $3.4 million, respectively, of cash collateral paid to third parties against short-term and long-term risk management liabilities.

The following tables represent the gross fair value impact of KPCo's derivative activity on the Condensed Balance Sheets as of June 30, 2011 and December 31, 2010:

Fair Value of Derivative Instruments
June 30, 2011

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate (a)	Other (a) (b)	Total
		(in thousands)			
Current Risk Management Assets	$ 39,949	$ 791	$ -	$ (33,955)	$ 6,785
Long-term Risk Management Assets	15,925	143	-	(9,215)	6,853
Total Assets	55,874	934	-	(43,170)	13,638
Current Risk Management Liabilities	38,874	578	-	(35,455)	3,997
Long-term Risk Management Liabilities	11,968	94	-	(9,849)	2,213
Total Liabilities	50,842	672	-	(45,304)	6,210
Total MTM Derivative Contract Net Assets (Liabilities)	$ 5,032	$ 262	$ -	$ 2,134	$ 7,428

Fair Value of Derivative Instruments
December 31, 2010

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate (a)	Other (a) (b)	Total
		(in thousands)			
Current Risk Management Assets	$ 60,231	$ 418	$ -	$ (51,952)	$ 8,697
Long-term Risk Management Assets	16,978	148	-	(9,096)	8,030
Total Assets	77,209	566	-	(61,048)	16,727
Current Risk Management Liabilities	59,107	490	-	(53,638)	5,959
Long-term Risk Management Liabilities	13,265	146	-	(11,108)	2,303
Total Liabilities	72,372	636	-	(64,746)	8,262
Total MTM Derivative Contract Net Assets (Liabilities)	$ 4,837	$ (70)	$ -	$ 3,698	$ 8,465

(a) Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented on the Condensed Balance Sheets on a net basis in accordance with the accounting guidance for "Derivatives and Hedging."

(b) Amounts include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging." Amounts also include dedesignated risk management contracts.

The table below presents KPCo's activity of derivative risk management contracts for the three and six months ended June 30, 2011 and 2010:

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Three and Six Months Ended June 30, 2011 and 2010

	Three Months Ended June 30,		Six Months Ended June 30,	
Location of Gain (Loss)	**2011**	**2010**	**2011**	**2010**
		(in thousands)		
Electric Generation, Transmission and Distribution Revenues	$ 885	$ (27)	$ 2,986	$ 4,608
Sales to AEP Affiliates	2	(15)	5	(756)
Regulatory Assets (a)	(43)	-	50	-
Regulatory Liabilities (a)	275	(605)	111	(66)
Total Gain (Loss) on Risk Management Contracts	$ 1,119	$ (647)	$ 3,152	$ 3,786

(a) Represents realized and unrealized gains and losses subject to regulatory accounting treatment recorded as either current or noncurrent on the balance sheet.

Certain qualifying derivative instruments have been designated as normal purchase or normal sale contracts, as provided in the accounting guidance for "Derivatives and Hedging." Derivative contracts that have been designated as normal purchases or normal sales under that accounting guidance are not subject to MTM accounting treatment and are recognized on the Condensed Statements of Income on an accrual basis.

KPCo's accounting for the changes in the fair value of a derivative instrument depends on whether it qualifies for and has been designated as part of a hedging relationship and further, on the type of hedging relationship. Depending on the exposure, management designates a hedging instrument as a fair value hedge or a cash flow hedge.

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in Revenues on a net basis on KPCo's Condensed Statements of Income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in Revenues or Expenses on KPCo's Condensed Statements of Income depending on the relevant facts and circumstances. However, unrealized and some realized gains and losses for both trading and non-trading derivative instruments are recorded as regulatory assets (for losses) or regulatory liabilities (for gains), in accordance with the accounting guidance for "Regulated Operations."

Accounting for Fair Value Hedging Strategies

For fair value hedges (i.e. hedging the exposure to changes in the fair value of an asset, liability or an identified portion thereof attributable to a particular risk), the gain or loss on the derivative instrument as well as the offsetting gain or loss on the hedged item associated with the hedged risk affects Net Income during the period of change.

KPCo records realized and unrealized gains or losses on interest rate swaps that qualify for fair value hedge accounting treatment and any offsetting changes in the fair value of the debt being hedged in Interest Expense on KPCo's Condensed Statements of Income. During the three and six months ended June 30, 2011 and 2010, KPCo did not employ any fair value hedging strategies.

Accounting for Cash Flow Hedging Strategies

For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows that is attributable to a particular risk), KPCo initially reports the effective portion of the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income (Loss) on the Condensed Balance Sheets until the period the hedged item affects Net Income. KPCo recognizes any hedge ineffectiveness as a regulatory asset (for losses) or a regulatory liability (for gains).

Realized gains and losses on derivatives contracts for the purchase and sale of power, coal, natural gas and heating oil and gasoline designated as cash flow hedges are included in Revenues, Fuel and Other Consumables Used for Electric Generation or Purchased Electricity for Resale on KPCo's Condensed Statements of Income, or in Regulatory Assets or Regulatory Liabilities on KPCo's Condensed Balance Sheets, depending on the specific nature of the risk being hedged. During the three and six months ended June 30, 2011 and 2010, KPCo designated commodity derivatives as cash flow hedges.

KPCo reclassifies gains and losses on financial fuel derivative contracts designated as cash flow hedges from Accumulated Other Comprehensive Income (Loss) on its Condensed Balance Sheets into Other Operation expense, Maintenance expense or Depreciation and Amortization expense, as it relates to capital projects, on the Condensed Statements of Income. During the three and six months ended June 30, 2011 and 2010, KPCo designated heating oil and gasoline derivatives as cash flow hedges.

KPCo reclassifies gains and losses on interest rate derivative hedges related to debt financings from Accumulated Other Comprehensive Income (Loss) into Interest Expense in those periods in which hedged interest payments occur. During the three and six months ended June 30, 2011 and 2010, KPCo did not designate any cash flow hedging strategies for interest rate derivative hedges.

The accumulated gains or losses related to foreign currency hedges are reclassified from Accumulated Other Comprehensive Income (Loss) on KPCo's Condensed Balance Sheets into Depreciation and Amortization expense on the Condensed Statements of Income over the depreciable lives of the fixed assets that were designated as the hedged items in qualifying foreign currency hedging relationships. During the three and six months ended June 30, 2011 and 2010, KPCo did not employ any foreign currency hedges.

During the three and six months ended June 30, 2011 and 2010, hedge ineffectiveness was immaterial or nonexistent for all hedge strategies disclosed above.

The following tables provide details on designated, effective cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's Condensed Balance Sheets and the reasons for changes in cash flow hedges for the three and six months ended June 30, 2011 and 2010. All amounts in the following tables are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
For the Three Months Ended June 30, 2011

	Commodity	Interest Rate	Total
		(in thousands)	
Balance in AOCI as of March 31, 2011	$ 72	$ (388)	$ (316)
Changes in Fair Value Recognized in AOCI	(13)	-	(13)
Amount of (Gain) or Loss Reclassified from AOCI to Income Statement/within Balance Sheet:			
Electric Generation, Transmission and Distribution Revenues	176	-	176
Purchased Electricity for Resale	(41)	-	(41)
Other Operation Expense	(11)	-	(11)
Maintenance Expense	(15)	-	(15)
Interest Expense	-	15	15
Property, Plant and Equipment	(15)	-	(15)
Balance in AOCI as of June 30, 2011	$ 153	$ (373)	$ (220)

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
For the Three Months Ended June 30, 2010

	Commodity	Interest Rate (in thousands)	Total
Balance in AOCI as of March 31, 2010	$ (505)	$ (448)	$ (953)
Changes in Fair Value Recognized in AOCI	131	-	131
Amount of (Gain) or Loss Reclassified from AOCI			
to Income Statement/within Balance Sheet:			
Electric Generation, Transmission and Distribution Revenues	29	-	29
Purchased Electricity for Resale	62	-	62
Other Operation Expense	(5)	-	(5)
Maintenance Expense	(6)	-	(6)
Interest Expense	-	15	15
Property, Plant and Equipment	(7)	-	(7)
Balance in AOCI as of June 30, 2010	$ (301)	$ (433)	$ (734)

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
For the Six Months Ended June 30, 2011

	Commodity	Interest Rate (in thousands)	Total
Balance in AOCI as of December 31, 2010	$ (48)	$ (403)	$ (451)
Changes in Fair Value Recognized in AOCI	40	-	40
Amount of (Gain) or Loss Reclassified from AOCI			
to Income Statement/within Balance Sheet:			
Electric Generation, Transmission and Distribution Revenues	172	-	172
Purchased Electricity for Resale	46	-	46
Other Operation Expense	(16)	-	(16)
Maintenance Expense	(20)	-	(20)
Interest Expense	-	30	30
Property, Plant and Equipment	(21)	-	(21)
Balance in AOCI as of June 30, 2011	$ 153	$ (373)	$ (220)

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
For the Six Months Ended June 30, 2010

	Commodity	Interest Rate (in thousands)	Total
Balance in AOCI as of December 31, 2009	$ (138)	$ (463)	$ (601)
Changes in Fair Value Recognized in AOCI	(397)	-	(397)
Amount of (Gain) or Loss Reclassified from AOCI			
to Income Statement/within Balance Sheet:			
Electric Generation, Transmission and Distribution Revenues	54	-	54
Purchased Electricity for Resale	205	-	205
Other Operation Expense	(7)	-	(7)
Maintenance Expense	(9)	-	(9)
Interest Expense	-	30	30
Property, Plant and Equipment	(9)	-	(9)
Balance in AOCI as of June 30, 2010	$ (301)	$ (433)	$ (734)

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's Condensed Balance Sheets at June 30, 2011 and December 31, 2010 were:

Impact of Cash Flow Hedges on the Condensed Balance Sheet
June 30, 2011

	Commodity	Interest Rate	Total
		(in thousands)	
Hedging Assets (a)	$ 374	$ -	$ 374
Hedging Liabilities (a)	112	-	112
AOCI Gain (Loss) Net of Tax	153	(373)	(220)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	118	(60)	58

Impact of Cash Flow Hedges on the Condensed Balance Sheet
December 31, 2010

	Commodity	Interest Rate	Total
		(in thousands)	
Hedging Assets (a)	$ 81	$ -	$ 81
Hedging Liabilities (a)	151	-	151
AOCI Loss Net of Tax	(48)	(403)	(451)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	(48)	(60)	(108)

(a) Hedging Assets and Hedging Liabilities are included in Risk Management Assets and Liabilities on KPCo's Condensed Balance Sheets.

The actual amounts that KPCo reclassifies from Accumulated Other Comprehensive Income (Loss) to Net Income can differ from the estimate above due to market price changes. As of June 30, 2011, the maximum length of time that KPCo is hedging (with contracts subject to the accounting guidance for "Derivatives and Hedging") exposure to variability in future cash flows related to forecasted transactions is 35 months.

Credit Risk

AEPSC, on behalf of KPCo, limits credit risk in KPCo's wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. AEPSC, on behalf of KPCo, uses Moody's, Standard and Poor's and current market-based qualitative and quantitative data as well as financial statements to assess the financial health of counterparties on an ongoing basis.

AEPSC, on behalf of KPCo, uses standardized master agreements which may include collateral requirements. These master agreements facilitate the netting of cash flows associated with a single counterparty. Cash, letters of credit and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. The collateral agreements require a counterparty to post cash or letters of credit in the event an exposure exceeds the established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with AEP's credit policy. In addition, collateral agreements allow for termination and liquidation of all positions in the event of a failure or inability to post collateral.

Collateral Triggering Events

Under the tariffs of the RTOs and Independent System Operators (ISOs) and a limited number of derivative and non-derivative contracts primarily related to competitive retail auction loads, KPCo is obligated to post an additional amount of collateral if certain credit ratings decline below investment grade. The amount of collateral required fluctuates based on market prices and total exposure. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these collateral triggering items in contracts. Management does not anticipate a downgrade below investment grade. The following table represents: (a) the aggregate fair value of such derivative contracts, (b) the amount of collateral KPCo would have been required to post for all derivative and non-derivative contracts if the credit ratings had declined below investment grade and (c) how much was attributable to RTO and ISO activities as of June 30, 2011 and December 31, 2010:

	June 30, 2011	December 31, 2010
	(in thousands)	
Liabilities for Derivative Contracts with Credit Downgrade Triggers	$ 2,013	$ 1,368
Amount of Collateral KPCo Would Have Been Required to Post	1,559	2,614
Amount Attributable to RTO and ISO Activities	1,559	2,608

As of June 30, 2011 and December 31, 2010, KPCo was not required to post any collateral.

In addition, a majority of KPCo's non-exchange traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event by Parent or the obligor under outstanding debt or a third party obligation in excess of $50 million. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-default provisions in the contracts. Management does not anticipate a non-performance event under these provisions. The following table represents: (a) the fair value of these derivative liabilities subject to cross-default provisions prior to consideration of contractual netting arrangements, (b) the amount this exposure has been reduced by cash collateral posted by KPCo and (c) if a cross-default provision would have been triggered, the settlement amount that would be required after considering KPCo's contractual netting arrangements as of June 30, 2011 and December 31, 2010:

	June 30, 2011	December 31, 2010
	(in thousands)	
Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	$ 13,405	$ 15,930
Amount of Cash Collateral Posted	636	1,376
Additional Settlement Liability if Cross Default Provision is Triggered	3,925	4,926

8. FAIR VALUE MEASUREMENTS

Fair Value Hierarchy and Valuation Techniques

The accounting guidance for "Fair Value Measurements and Disclosures" establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. When quoted market prices are not available, pricing may be completed using comparable securities, dealer values, operating data and general market conditions to determine fair value. Valuation models utilize various inputs such as commodity, interest rate and, to a lesser degree, volatility and credit that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability.

For commercial activities, exchange traded derivatives, namely futures contracts, are generally fair valued based on unadjusted quoted prices in active markets and are classified as Level 1. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, as well as exchange traded contracts where there is insufficient market liquidity to warrant inclusion in Level 1. Management verifies price curves using these broker quotes and classifies these fair values within Level 2 when substantially all of the fair value can be corroborated. Management typically obtains multiple broker quotes, which are non-binding in nature but are based on recent trades in the marketplace. When multiple broker quotes are obtained, the quoted bid and ask prices are averaged. In certain circumstances, a broker quote may be discarded if it is a clear outlier. Management uses a historical correlation analysis between the broker quoted location and the illiquid locations. If the points are highly correlated, these locations are included within Level 2 as well. Certain OTC and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. Long-dated and illiquid complex or structured transactions and FTRs can introduce the need for internally developed modeling inputs based upon extrapolations and assumptions of observable market data to estimate fair value. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized as Level 3.

Fair Value Measurements of Long-term Debt

The fair values of Long-term Debt are based on quoted market prices, without credit enhancements, for the same or similar issues and the current interest rates offered for instruments with similar maturities. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that could be realized in a current market exchange.

The book values and fair values of KPCo's Long-term Debt as of June 30, 2011 and December 31, 2010 are summarized in the following table:

	June 30, 2011		December 31, 2010	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
Long-term Debt	$ 548,972	$ 641,786	$ 548,888	$ 628,623

Fair Value Measurements of Financial Assets and Liabilities

The following tables set forth, by level within the fair value hierarchy, KPCo's financial assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2011 and December 31, 2010. As required by the accounting guidance for "Fair Value Measurements and Disclosures," financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There have not been any significant changes in management's valuation techniques.

Assets and Liabilities Measured at Fair Value on a Recurring Basis
June 30, 2011

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (c)	$ 198	$ 51,167	$ 3,521	$ (42,185)	$ 12,701
Cash Flow Hedges:					
Commodity Hedges (a)	-	924	-	(550)	374
Dedesignated Risk Management Contracts (b)	-	-	-	563	563
Total Risk Management Assets	$ 198	$ 52,091	$ 3,521	$ (42,172)	$ 13,638
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (c)	$ 191	$ 47,280	$ 2,383	$ (43,756)	$ 6,098
Cash Flow Hedges:					
Commodity Hedges (a)	-	651	11	(550)	112
Total Risk Management Liabilities	$ 191	$ 47,931	$ 2,394	$ (44,306)	$ 6,210

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2010

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (c)	$ 350	$ 73,753	$ 2,862	$ (61,018)	$ 15,947
Cash Flow Hedges:					
Commodity Hedges (a)	-	549	-	(468)	81
Dedesignated Risk Management Contracts (b)	-	-	-	699	699
Total Risk Management Assets	$ 350	$ 74,302	$ 2,862	$ (60,787)	$ 16,727
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (c)	$ 343	$ 69,996	$ 1,789	$ (64,017)	$ 8,111
Cash Flow Hedges:					
Commodity Hedges (a)	-	619	-	(468)	151
Total Risk Management Liabilities	$ 343	$ 70,615	$ 1,789	$ (64,485)	$ 8,262

(a) Amounts in "Other" column primarily represent counterparty netting of risk management and hedging contracts and associated cash collateral under the accounting guidance for "Derivatives and Hedging."

(b) Represents contracts that were originally MTM but were subsequently elected as normal under the accounting guidance for "Derivatives and Hedging." At the time of the normal election, the MTM value was frozen and no longer fair valued. This MTM value will be amortized into revenues over the remaining life of the contracts.

(c) Substantially comprised of power contracts.

There were no transfers between Level 1 and Level 2 during the six months ended June 30, 2011 and 2010.

The following tables set forth a reconciliation of changes in the fair value of net trading derivatives and other investments classified as Level 3 in the fair value hierarchy:

Three Months Ended June 30, 2011	Net Risk Management Assets (Liabilities) (in thousands)
Balance as of March 31, 2011	$ 1,146
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(681)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	(11)
Purchases, Issuances and Settlements (c)	1,019
Transfers into Level 3 (d) (f)	236
Transfers out of Level 3 (e) (f)	(45)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	(537)
Balance as of June 30, 2011	$ 1,127

Three Months Ended June 30, 2010	Net Risk Management Assets (Liabilities) (in thousands)
Balance as of March 31, 2010	$ 3,908
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(1,744)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-
Purchases, Issuances and Settlements (c)	1,005
Transfers into Level 3 (d) (f)	279
Transfers out of Level 3 (e) (f)	(420)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	(774)
Balance as of June 30, 2010	$ 2,254

Six Months Ended June 30, 2011	Net Risk Management Assets (Liabilities) (in thousands)
Balance as of December 31, 2010	$ 1,073
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(525)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	(11)
Purchases, Issuances and Settlements (c)	824
Transfers into Level 3 (d) (f)	255
Transfers out of Level 3 (e) (f)	(592)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	103
Balance as of June 30, 2011	$ 1,127

Six Months Ended June 30, 2010	Net Risk Management Assets (Liabilities) (in thousands)
Balance as of December 31, 2009	$ 1,899
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	270
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-
Purchases, Issuances and Settlements (c)	(876)
Transfers into Level 3 (d) (f)	122
Transfers out of Level 3 (e) (f)	(362)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	1,201
Balance as of June 30, 2010	$ 2,254

(a) Included in revenues on KPCo's Condensed Statements of Income.
(b) Represents the change in fair value between the beginning of the reporting period and the settlement of the risk management commodity contract.
(c) Represents the settlement of risk management commodity contracts for the reporting period.
(d) Represents existing assets or liabilities that were previously categorized as Level 2.
(e) Represents existing assets or liabilities that were previously categorized as Level 3.
(f) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.
(g) Relates to the net gains (losses) of those contracts that are not reflected on KPCo's Condensed Statements of Income. These net gains (losses) are recorded as regulatory assets/liabilities.

9. INCOME TAXES

KPCo joins in the filing of a consolidated federal income tax return with its affiliates in the AEP System. The allocation of the AEP System's current consolidated federal income tax to the AEP System companies allocates the benefit of current tax losses to the AEP System companies giving rise to such losses in determining their current tax expense. The tax benefit of the Parent is allocated to its subsidiaries with taxable income. With the exception of the loss of the Parent, the method of allocation reflects a separate return result for each company in the consolidated group.

KPCo and other AEP subsidiaries are no longer subject to U.S. federal examination for years before 2001. KPCo and other AEP subsidiaries have completed the exam for the years 2001 through 2006 and have issues that are being pursued at the appeals level. In April 2011, the IRS's examination of the years 2007 and 2008 was concluded with a settlement of all outstanding issues. The settlement will not have a material impact on net income, cash flows or financial condition. Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for federal income taxes have been made for potential liabilities resulting from such matters. In addition, KPCo accrues interest on these uncertain tax positions. Management is not aware of any issues for open tax years that upon final resolution are expected to have a material adverse effect on net income.

KPCo and other AEP subsidiaries file income tax returns in various state and local jurisdictions. These taxing authorities routinely examine the tax returns and KPCo and other AEP subsidiaries are currently under examination in several state and local jurisdictions. Management believes that previously filed tax returns have positions that may be challenged by these tax authorities. However, management believes that adequate provisions for income taxes have been made for potential liabilities resulting from such challenges and that the ultimate resolution of these audits will not materially impact net income. With few exceptions, KPCo is no longer subject to state or local income tax examinations by tax authorities for years before 2000.

Federal Legislation

The Patient Protection and Affordable Care Act and the related Health Care and Education Reconciliation Act (Health Care Acts) were enacted in March 2010. The Health Care Acts amend tax rules so that the portion of employer health care costs that are reimbursed by the Medicare Part D prescription drug subsidy will no longer be deductible by the employer for federal income tax purposes effective for years beginning after December 31, 2012. Because of the loss of the future tax deduction, a reduction in the deferred tax asset related to the nondeductible OPEB liabilities accrued to date was recorded by KPCo in March 2010. This reduction, which was offset by recording net tax regulatory assets, did not materially affect KPCo's net income, cash flows or financial condition.

The Small Business Jobs Act (the Act) was enacted in September 2010. Included in the Act was a one-year extension of the 50% bonus depreciation provision. The Tax Relief, Unemployment Insurance Reauthorization and the Job Creation Act of 2010 extended the life of research and development, employment and several energy tax credits originally scheduled to expire at the end of 2010. In addition, the Act extended the time for claiming bonus depreciation and increased the deduction to 100% for part of 2010 and 2011. The enacted provisions will not have a material impact on KPCo's net income or financial condition.

State Tax Legislation

Michigan repealed its Business Tax regime in May 2011 and replaced it with a traditional corporate net income tax with a rate of 6%. The enacted provision will not have a material impact on KPCo's net income, cash flows or financial condition.

10. FINANCING ACTIVITIES

Long-term Debt

KPCo did not have any long-term debt issuances or retirements during the first six months of 2011.

Dividend Restrictions

Federal Power Act

The Federal Power Act prohibits KPCo from participating "in the making or paying of any dividends of such public utility from any funds properly included in capital account." The term "capital account" is not defined in the Federal Power Act or its regulations. Management understands "capital account" to mean the par value of the common stock multiplied by the number of shares outstanding. This restriction does not limit the ability of KPCo to pay dividends out of retained earnings.

Utility Money Pool – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of its subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds the utility subsidiaries. The AEP System Utility Money Pool operates in accordance with the terms and conditions approved in a regulatory order. The amount of outstanding loans to the Utility Money Pool as of June 30, 2011 and December 31, 2010 is included in Advances to Affiliates on KPCo's balance sheets. KPCo's Utility Money Pool activity and corresponding authorized borrowing limits for the six months ended June 30, 2011 are described in the following table:

Maximum Borrowings from Utility Money Pool	Maximum Loans to Utility Money Pool	Average Borrowings from Utility Money Pool	Average Loans to Utility Money Pool	Loans to Utility Money Pool as of June 30, 2011	Authorized Short-Term Borrowing Limit
		(in thousands)			
$ -	$ 110,375	$ -	$ 86,437	$ 85,653	$ 250,000

Maximum, minimum and average interest rates for funds either borrowed from or loaned to the Utility Money Pool for the six months ended June 30, 2011 and 2010 are summarized in the following table:

Year	Maximum Interest Rates for Funds Borrowed from Utility Money Pool	Minimum Interest Rates for Funds Borrowed from Utility Money Pool	Maximum Interest Rates for Funds Loaned to Utility Money Pool	Minimum Interest Rates for Funds Loaned to Utility Money Pool	Average Interest Rates for Funds Borrowed from Utility Money Pool	Average Interest Rates for Funds Loaned to Utility Money Pool
2011	- %	- %	0.56 %	0.06 %	- %	0.29 %
2010	0.51 %	0.09 %	0.36 %	0.09 %	0.34 %	0.16 %

Sale of Receivables – AEP Credit

Under a sale of receivables arrangement, KPCo sells, without recourse, certain of its customer accounts receivable and accrued unbilled revenue balances to AEP Credit and is charged a fee based on AEP Credit's financing costs, administrative costs and uncollectible accounts experience for KPCo's receivables. The costs of customer accounts receivable sold are reported in Other Operation on KPCo's income statement. KPCo manages and services its accounts receivable sold.

In July 2011, AEP Credit renewed its receivables securitization agreement. The agreement provides commitments of $750 million from bank conduits to finance receivables from AEP Credit with an increase to $800 million for the months of July, August and September to accommodate seasonal demand. A commitment of $375 million, with the seasonal increase to $425 million for the months of July, August and September, expires in June 2012 and the remaining commitment of $375 million expires in June 2014.

KPCo's amount of accounts receivable and accrued unbilled revenues sold under the sale of receivables agreement was $55 million and $63 million as of June 30, 2011 and December 31, 2010, respectively.

The fees paid by KPCo to AEP Credit for customer accounts receivable sold were $538 thousand and $1.1 million for the three and six months ended June 30, 2011, respectively, and $512 thousand and $1.1 million for the three and six months ended June 30, 2010, respectively.

KPCo's proceeds on the sale of receivables to AEP Credit were $129 million and $302 million for the three and six months ended June 30, 2011, respectively, and $112 million and $257 million for the three and six months ended June 30, 2010, respectively.

11. COST REDUCTION INITIATIVES

In April 2010, management began initiatives to decrease both labor and non-labor expenses with a goal of achieving significant reductions in operation and maintenance expenses. A total of 2,461 positions was eliminated across the AEP System as a result of process improvements, streamlined organizational designs and other efficiencies. Most of the affected employees terminated employment May 31, 2010. The severance program provided two weeks of base pay for every year of service along with other severance benefits.

KPCo recorded a charge of $11.7 million to Other Operation expense during the second quarter of 2010 primarily related to severance benefits as the result of headcount reduction initiatives.

The following table shows the cost reduction activity for the six months ended June 30, 2011:

Balance at December 31, 2010	Incurred	Settled	Adjustments	Balance at June 30, 2011
		(in thousands)		
$ 1,018	$ -	$ (374)	$ (332)	$ 312

The remaining accrual is included in Other Current Liabilities on the Condensed Balance Sheets.

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Kentucky Power Company

2011 Third Quarter Report

Financial Statements

AEP AMERICAN ELECTRIC POWER

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GLOSSARY OF TERMS

When the following terms and abbreviations appear in the text of this report, they have the meanings indicated below.

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP or Parent	American Electric Power Company, Inc., a holding company.
AEP Credit	AEP Credit, Inc., a subsidiary of AEP which factors accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP East companies	APCo, CSPCo, I&M, KPCo and OPCo.
AEP Power Pool	Members are APCo, CSPCo, I&M, KPCo and OPCo. The Pool shares the generation, cost of generation and resultant wholesale off-system sales of the member companies.
AEP System or the System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEPSC	American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
ASU	Accounting Standard Update.
CAA	Clean Air Act.
CO_2	Carbon Dioxide and other greenhouse gases.
CSPCo	Columbus Southern Power Company, an AEP electric utility subsidiary.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
GAAP	Accounting Principles Generally Accepted in the United States of America.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
MISO	Midwest Independent Transmission System Operator.
MMBtu	Million British Thermal Units.
MTM	Mark-to-Market.
MW	Megawatt.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefit Plans.
OTC	Over the counter.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generating plant, consisting of two 1,300 MW coal-fired generating units near Rockport, Indiana.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
SIA	System Integration Agreement, effective June 15, 2000, provides contractual basis for coordinated planning, operation and maintenance of the power supply sources of the combined AEP.

Term	Meaning
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
Utility Money Pool	AEP System's Utility Money Pool is the centralized funding mechanism AEP uses to meet the short term cash requirements of pool participants.
VIE	Variable Interest Entity.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2011 and 2010
(in thousands)
(Unaudited)

	Three Months Ended 2011	Three Months Ended 2010	Nine Months Ended 2011	Nine Months Ended 2010
REVENUES				
Electric Generation, Transmission and Distribution	$ 167,533	$ 166,420	$ 501,647	$ 456,265
Sales to AEP Affiliates	18,734	22,733	55,169	43,678
Other Revenues	177	264	420	364
TOTAL REVENUES	186,444	189,417	557,236	500,307
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	47,994	53,623	164,619	140,348
Purchased Electricity for Resale	5,405	5,573	16,990	14,910
Purchased Electricity from AEP Affiliates	60,207	55,815	163,495	158,539
Other Operation	16,792	13,562	48,101	51,902
Maintenance	13,611	12,778	39,947	31,949
Depreciation and Amortization	13,516	13,271	40,376	39,529
Taxes Other Than Income Taxes	3,056	1,469	8,006	7,955
TOTAL EXPENSES	160,581	156,091	481,534	445,132
OPERATING INCOME	25,863	33,326	75,702	55,175
Other Income (Expense):				
Interest Income	1,408	55	1,620	157
Allowance for Equity Funds Used During Construction	300	106	813	548
Interest Expense	(9,172)	(9,299)	(27,545)	(27,611)
INCOME BEFORE INCOME TAX EXPENSE	18,399	24,188	50,590	28,269
Income Tax Expense	6,546	8,243	18,395	9,878
NET INCOME	$ 11,853	$ 15,945	$ 32,195	$ 18,391

The common stock of KPCo is wholly-owned by AEP.

See Condensed Notes to Condensed Financial Statements.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Nine Months Ended September 30, 2011 and 2010
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2009	$ 50,450	$ 238,750	$ 143,185	$ (601)	$ 431,784
Common Stock Dividends			(15,000)		(15,000)
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					416,784
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $138				(256)	(256)
NET INCOME			18,391		18,391
TOTAL COMPREHENSIVE INCOME					18,135
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2010	$ 50,450	$ 238,750	$ 146,576	$ (857)	$ 434,919
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2010	$ 50,450	$ 238,750	$ 157,467	$ (451)	$ 446,216
Common Stock Dividends			(18,000)		(18,000)
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					428,216
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $41				76	76
NET INCOME			32,195		32,195
TOTAL COMPREHENSIVE INCOME					32,271
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2011	$ 50,450	$ 238,750	$ 171,662	$ (375)	$ 460,487

See Condensed Notes to Condensed Financial Statements.

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
ASSETS
September 30, 2011 and December 31, 2010
(in thousands)
(Unaudited)

	2011	2010
CURRENT ASSETS		
Cash and Cash Equivalents	$ 809	$ 281
Advances to Affiliates	95,669	67,060
Accounts Receivable:		
Customers	10,549	21,652
Affiliated Companies	10,703	17,616
Accrued Unbilled Revenues	1,677	3,823
Miscellaneous	432	587
Allowance for Uncollectible Accounts	(644)	(623)
Total Accounts Receivable	22,717	43,055
Fuel	15,044	16,640
Materials and Supplies	12,926	24,378
Risk Management Assets	6,387	8,697
Accrued Tax Benefits	-	1,420
Margin Deposits	3,071	5,357
Prepayments and Other Current Assets	2,754	1,497
TOTAL CURRENT ASSETS	159,377	168,385
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	555,065	553,589
Transmission	455,584	444,303
Distribution	605,935	590,606
Other Property, Plant and Equipment	64,453	63,982
Construction Work in Progress	38,886	34,093
Total Property, Plant and Equipment	1,719,923	1,686,573
Accumulated Depreciation and Amortization	571,166	542,443
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	1,148,757	1,144,130
OTHER NONCURRENT ASSETS		
Regulatory Assets	205,714	213,593
Long-term Risk Management Assets	5,122	8,030
Deferred Charges and Other Noncurrent Assets	37,019	37,946
TOTAL OTHER NONCURRENT ASSETS	247,855	259,569
TOTAL ASSETS	$ 1,555,989	$ 1,572,084

See Condensed Notes to Condensed Financial Statements.

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
LIABILITIES AND SHAREHOLDER'S EQUITY
September 30, 2011 and December 31, 2010
(Unaudited)

	2011	2010
	(in thousands)	
CURRENT LIABILITIES		
Accounts Payable:		
General	$ 27,711	$ 33,334
Affiliated Companies	28,112	45,790
Risk Management Liabilities	4,087	5,959
Customer Deposits	21,160	19,692
Accrued Taxes	21,288	23,741
Accrued Interest	6,414	7,570
Other Current Liabilities	17,654	26,227
TOTAL CURRENT LIABILITIES	126,426	162,313
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	529,013	528,888
Long-term Debt – Affiliated	20,000	20,000
Long-term Risk Management Liabilities	1,524	2,303
Deferred Income Taxes	328,703	316,389
Regulatory Liabilities and Deferred Investment Tax Credits	35,363	34,991
Employee Benefits and Pension Obligations	44,535	49,298
Deferred Credits and Other Noncurrent Liabilities	9,938	11,686
TOTAL NONCURRENT LIABILITIES	969,076	963,555
TOTAL LIABILITIES	1,095,502	1,125,868
Rate Matters (Note 3)		
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $50 Per Share:		
Authorized – 2,000,000 Shares		
Outstanding – 1,009,000 Shares	50,450	50,450
Paid-in Capital	238,750	238,750
Retained Earnings	171,662	157,467
Accumulated Other Comprehensive Income (Loss)	(375)	(451)
TOTAL COMMON SHAREHOLDER'S EQUITY	460,487	446,216
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$ 1,555,989	$ 1,572,084

See Condensed Notes to Condensed Financial Statements.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2011 and 2010
(in thousands)
(Unaudited)

		2011		2010
OPERATING ACTIVITIES				
Net Income	$	32,195	$	18,391
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:				
Depreciation and Amortization		40,376		39,529
Deferred Income Taxes		8,855		3,384
Allowance for Equity Funds Used During Construction		(813)		(548)
Mark-to-Market of Risk Management Contracts		2,621		(946)
Pension Contributions to Qualified Plan Trust		(2,499)		(5,292)
Property Taxes		5,840		7,036
Fuel Over/Under-Recovery, Net		(1,187)		(246)
Change in Other Noncurrent Assets		248		3,972
Change in Other Noncurrent Liabilities		(156)		(1,191)
Changes in Certain Components of Working Capital:				
Accounts Receivable, Net		20,375		8,406
Fuel, Materials and Supplies		13,048		29,487
Accounts Payable		(22,941)		(22,409)
Accrued Taxes, Net		(2,472)		19,737
Other Current Assets		1,367		(155)
Other Current Liabilities		(928)		(3,057)
Net Cash Flows from Operating Activities		93,929		96,098
INVESTING ACTIVITIES				
Construction Expenditures		(46,025)		(36,765)
Change in Advances to Affiliates, Net		(28,609)		(42,823)
Acquisitions of Assets		(59)		(214)
Proceeds from Sales of Assets		390		586
Net Cash Flows Used for Investing Activities		(74,303)		(79,216)
FINANCING ACTIVITIES				
Change in Advances from Affiliates, Net		-		(485)
Principal Payments for Capital Lease Obligations		(1,148)		(1,280)
Dividends Paid on Common Stock		(18,000)		(15,000)
Other Financing Activities		50		10
Net Cash Flows Used for Financing Activities		(19,098)		(16,755)
Net Increase in Cash and Cash Equivalents		528		127
Cash and Cash Equivalents at Beginning of Period		281		494
Cash and Cash Equivalents at End of Period	$	809	$	621
SUPPLEMENTARY INFORMATION				
Cash Paid for Interest, Net of Capitalized Amounts	$	28,528	$	28,229
Net Cash Paid (Received) for Income Taxes		7,272		(14,883)
Noncash Acquisitions Under Capital Leases		8		4,191
Construction Expenditures Included in Current Liabilities at September 30,		3,495		2,431

See Condensed Notes to Condensed Financial Statements.

INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS

1. SIGNIFICANT ACCOUNTING MATTERS

General

The unaudited condensed financial statements and footnotes were prepared in accordance with GAAP for interim financial information. Accordingly, they do not include all of the information and footnotes required by GAAP for complete annual financial statements.

In the opinion of management, the unaudited condensed interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair presentation of the net income, financial position and cash flows for the interim periods. Net income for the three and nine months ended September 30, 2011 is not necessarily indicative of results that may be expected for the year ending December 31, 2011. The condensed financial statements are unaudited and should be read in conjunction with the audited 2010 financial statements and notes thereto, which are included in KPCo's 2010 Annual Report.

Management reviewed subsequent events through October 28, 2011, the date that the third quarter 2011 report was issued.

Variable Interest Entities

The accounting guidance for "Variable Interest Entities" is a consolidation model that considers if a company has a controlling financial interest in a VIE. A controlling financial interest will have both (a) the power to direct the activities of a VIE that most significantly impact the VIE's economic performance and (b) the obligation to absorb losses of the VIE that could potentially be significant to the VIE or the right to receive benefits from the VIE that could potentially be significant to the VIE. Entities are required to consolidate a VIE when it is determined that they have a controlling financial interest in a VIE and therefore, are the primary beneficiary of that VIE, as defined by the accounting guidance for "Variable Interest Entities." In determining whether KPCo is the primary beneficiary of a VIE, management considers factors such as equity at risk, the amount of the VIE's variability KPCo absorbs, guarantees of indebtedness, voting rights including kick-out rights, the power to direct the VIE and other factors. Management believes that significant assumptions and judgments were applied consistently. There have been no changes to the reporting of VIEs in the financial statements where it is concluded that KPCo is the primary beneficiary. In addition, KPCo has not provided financial or other support to any VIE that was not previously contractually required.

AEPSC provides certain managerial and professional services to AEP's subsidiaries. AEP is the sole equity owner of AEPSC. AEP management controls the activities of AEPSC. The costs of the services are based on a direct charge or on a prorated basis and billed to the AEP subsidiary companies at AEPSC's cost. AEP subsidiaries have not provided financial or other support outside the reimbursement of costs for services rendered. AEPSC finances its operations through cost reimbursement from other AEP subsidiaries. There are no other terms or arrangements between AEPSC and any of the AEP subsidiaries that could require additional financial support from an AEP subsidiary or expose them to losses outside of the normal course of business. AEPSC and its billings are subject to regulation by the FERC. AEP subsidiaries are exposed to losses to the extent they cannot recover the costs of AEPSC through their normal business operations. AEP subsidiaries are considered to have a significant interest in AEPSC due to their activity in AEPSC's cost reimbursement structure. However, AEP subsidiaries do not have control over AEPSC. AEPSC is consolidated by AEP. In the event AEPSC would require financing or other support outside the cost reimbursement billings, this financing would be provided by AEP. KPCo's total billings from AEPSC for the three months ended September 30, 2011 and 2010 were $9 million and $8 million, respectively, and for the nine months ended September 30, 2011 and 2010 were $24 million and $28 million, respectively. The carrying amount of liabilities associated with AEPSC as of September 30, 2011 and December 31, 2010 were both $3 million. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

AEGCo, a wholly-owned subsidiary of AEP, is consolidated by AEP. AEGCo owns a 50% ownership interest in Rockport Plant Unit 1 and leases a 50% interest in Rockport Plant Unit 2. AEGCo sells all the output from the Rockport Plant to I&M and KPCo. AEP guarantees all the debt obligations of AEGCo. KPCo is considered to have a significant interest in AEGCo due to its transactions. KPCo is exposed to losses to the extent it cannot recover the costs of AEGCo through its normal business operations. Due to AEP management's control over AEGCo, KPCo is not considered the primary beneficiary of AEGCo. In the event AEGCo would require financing or other support outside the billings to KPCo, this financing would be provided by AEP. Total billings from AEGCo for the three months ended September 30, 2011 and 2010 were $28 million and $27 million, respectively and for the nine months ended September 30, 2011 and 2010 were both $72 million. The carrying amount of liabilities associated with AEGCo as of September 30, 2011 and December 31, 2010 was $9 million and $10 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

2. NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of final pronouncements, management reviews the new accounting literature to determine its relevance, if any, to KPCo's business. The following represents a summary of final pronouncements that impact the financial statements.

Pronouncements Issued During 2011

The following standard was issued during the first nine months of 2011. The following paragraphs discuss its impact on future financial statements.

ASU 2011-05 "Presentation of Comprehensive Income" (ASU 2011-05)

In June 2011, the FASB issued ASU 2011-05 eliminating the option to present the components of other comprehensive income as a part of the statement of shareholders' equity. The standard requires other comprehensive income be presented as part of a single continuous statement of comprehensive income or in a statement of other comprehensive income immediately following the statement of net income.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2011. Early adoption is permitted. This standard must be retrospectively applied to all reporting periods presented in financial reports issued after the effective date. This standard will change the presentation of the financial statements but will not affect the calculation of net income or comprehensive income. The FASB is currently considering deferral of reclassification adjustment presentation provisions of ASU 2011-05. Absent a deferral of this accounting guidance in its entirety, management expects to adopt ASU 2011-05 for the 2011 Annual Report.

3. RATE MATTERS

As discussed in KPCo's 2010 Annual Report, KPCo is involved in rate and regulatory proceedings at the FERC and the KPSC. The Rate Matters note within KPCo's 2010 Annual Report should be read in conjunction with this report to gain a complete understanding of material rate matters still pending that could impact net income, cash flows and possibly financial condition. The following discusses ratemaking developments in 2011 and updates KPCo's 2010 Annual Report.

Regulatory Assets Not Yet Being Recovered

Noncurrent Regulatory Assets (excluding fuel)	September 30, 2011	December 31, 2010
	(in thousands)	
Regulatory assets not yet being recovered pending future proceedings to determine the recovery method and timing:		
Regulatory Assets Currently Not Earning a Return		
Mountaineer Carbon Capture and Storage Commercial Scale Facility	$ 1,314	$ -
Total Regulatory Assets Not Yet Being Recovered	$ 1,314	$ -

FERC Rate Matters

Seams Elimination Cost Allocation (SECA) Revenue Subject to Refund

In 2004, AEP eliminated transaction-based through-and-out transmission service (T&O) charges in accordance with FERC orders and collected, at the FERC's direction, load-based charges, referred to as RTO SECA, to partially mitigate the loss of T&O revenues on a temporary basis through March 2006. Intervenors objected to the temporary SECA rates. The FERC set SECA rate issues for hearing and ordered that the SECA rate revenues be collected, subject to refund. The AEP East companies recognized gross SECA revenues of $220 million from 2004 through 2006 when the SECA rates terminated. KPCo's portion of recognized gross SECA revenues was $17 million.

In 2006, a FERC Administrative Law Judge (ALJ) issued an initial decision finding that the SECA rates charged were unfair, unjust and discriminatory and that new compliance filings and refunds should be made. The ALJ also found that any unpaid SECA rates must be paid in the recommended reduced amount.

AEP filed briefs jointly with other affected companies asking the FERC to reverse the decision. In May 2010, the FERC issued an order that generally supports AEP's position and required a compliance filing to be filed with the FERC by August 2010. In June 2010, AEP and other affected companies filed a joint request for rehearing with the FERC. In September 2011, the FERC issued orders that denied all parties' request for rehearing of the initial decision.

The AEP East companies provided reserves for net refunds for SECA settlements totaling $44 million applicable to the $220 million of SECA revenues collected. KPCo provided a reserve of $3.3 million.

Settlements approved by the FERC consumed $10 million of the reserve for refunds applicable to $112 million of SECA revenue. In December 2010, the FERC issued an order approving a settlement agreement resulting in the collection of $2 million of previously deemed uncollectible SECA revenue. Therefore, the AEP East companies reduced their reserves for net refunds for SECA settlements by $2 million. The balance in the reserve for future settlements as of September 30, 2011 was $32 million. KPCo's portion of the reserve balance as of September 30, 2011 was $2.4 million.

In August 2010, the affected companies, including the AEP East companies, filed a compliance filing with the FERC. If the compliance filing is accepted, the AEP East companies would have to pay refunds of approximately $20 million including estimated interest of $5 million. The AEP East companies could also potentially receive payments up to approximately $10 million including estimated interest of $3 million. KPCo's portion of the potential refund payments and potential payments to be received are $1.5 million and $800 thousand, respectively. A decision is pending from the FERC.

Based on the AEP East companies' analysis of the May 2010 order and the compliance filing, management believes that the reserve is adequate to pay the refunds, including interest, that will be required should the May 2010 order or the compliance filing be made final. Management cannot predict the ultimate outcome of this proceeding at the FERC which could impact future net income and cash flows.

Possible Termination of the Interconnection Agreement

In December 2010, each of the AEP Power Pool members gave notice to AEPSC and each other of their decision to terminate the Interconnection Agreement effective January 2014 or such other date approved by FERC, subject to state regulatory input. No filings have been made at the FERC. It is unknown at this time whether the AEP Power Pool will be replaced by a new agreement among some or all of the members, whether individual companies will enter into bilateral or multi-party contracts with each other for power sales and purchases or asset transfers or if each company will choose to operate independently.

In addition, in September 2011, a stipulation agreement was filed for CSPCo and OPCo which proposed to dissolve and/or modify the Interconnection Agreement. A decision from the PUCO regarding the stipulation agreement is expected in the fourth quarter of 2011.

If any of the AEP Power Pool members experience decreases in revenues or increases in costs as a result of the termination of the AEP Power Pool and are unable to recover the change in revenues and costs through rates, prices or additional sales, it could reduce future net income and cash flows.

PJM/MISO Market Flow Calculation Settlement Adjustments

During 2009, an analysis conducted by MISO and PJM discovered several instances of unaccounted for power flows on numerous coordinated flowgates. These flows affected the settlement data for congestion revenues and expenses and dated back to the start of the MISO market in 2005. In January 2011, PJM and MISO reached a settlement agreement where the parties agreed to net various issues to zero. In June 2011, the FERC approved the settlement agreement.

4. COMMITMENTS, GUARANTEES AND CONTINGENCIES

KPCo is subject to certain claims and legal actions arising in its ordinary course of business. In addition, KPCo's business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation cannot be predicted. For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material effect on the financial statements. The Commitments, Guarantees and Contingencies note within KPCo's 2010 Annual Report should be read in conjunction with this report.

GUARANTEES

Liabilities for guarantees are recorded in accordance with the accounting guidance for "Guarantees." There is no collateral held in relation to any guarantees. In the event any guarantee is drawn, there is no recourse to third parties.

Indemnifications and Other Guarantees

Contracts

KPCo enters into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. As of September 30, 2011, there were no material liabilities recorded for any indemnifications.

KPCo, along with the other AEP East companies, PSO and SWEPCo, are jointly and severally liable for activity conducted by AEPSC on behalf of the AEP East companies, PSO and SWEPCo related to purchase power and sale activity conducted pursuant to the SIA.

Master Lease Agreements

KPCo leases certain equipment under master lease agreements. In December 2010, management signed a new master lease agreement with GE Capital Commercial Inc. (GE) to replace existing operating and capital leases with GE. These assets were included in existing master lease agreements that were to be terminated in 2011 since GE exercised the termination provision related to these leases in 2008. Certain previously leased assets were not included in the 2010 refinancing, but were purchased in January 2011.

For equipment under the GE master lease agreements, the lessor is guaranteed receipt of up to 78% of the unamortized balance of the equipment at the end of the lease term. If the fair value of the leased equipment is below the unamortized balance at the end of the lease term, KPCo is committed to pay the difference between the fair value and the unamortized balance, with the total guarantee not to exceed 78% of the unamortized balance. For equipment under other master lease agreements, the lessor is guaranteed a residual value up to a stated percentage of either the unamortized balance or the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, KPCo is committed to pay the difference between the actual fair value and the residual value guarantee. At September 30, 2011, the maximum potential loss for these lease agreements was approximately $651 thousand assuming the fair value of the equipment is zero at the end of the lease term. Historically, at the end of the lease term the fair value has been in excess of the unamortized balance.

CONTINGENCIES

Carbon Dioxide Public Nuisance Claims

In 2004, eight states and the City of New York filed an action in Federal District Court for the Southern District of New York against AEP, AEPSC, Cinergy Corp, Xcel Energy, Southern Company and Tennessee Valley Authority. The Natural Resources Defense Council, on behalf of three special interest groups, filed a similar complaint against the same defendants. The actions allege that CO_2 emissions from the defendants' power plants constitute a public nuisance under federal common law due to impacts of global warming and sought injunctive relief in the form of specific emission reduction commitments from the defendants. The trial court dismissed the lawsuits.

In September 2009, the Second Circuit Court of Appeals issued a ruling on appeal remanding the cases to the Federal District Court for the Southern District of New York. The Second Circuit held that the issues of climate change and global warming do not raise political questions and that Congress' refusal to regulate CO_2 emissions does not mean that plaintiffs must wait for an initial policy determination by Congress or the President's administration to secure the relief sought in their complaints. In 2010, the U.S. Supreme Court granted the defendants' petition for review. In June 2011, the U.S. Supreme Court reversed and remanded the case to the Court of Appeals, finding that plaintiffs' federal common law claims are displaced by the regulatory authority granted to the Federal EPA under the CAA. After the remand, the plaintiffs asked the Second Circuit to return the case to the district court so that they could withdraw their complaints. The cases have been returned to the district court and the parties have been ordered to advise the court in November 2011 how they intend to proceed.

In October 2009, the Fifth Circuit Court of Appeals reversed a decision by the Federal District Court for the District of Mississippi dismissing state common law nuisance claims in a putative class action by Mississippi residents asserting that CO_2 emissions exacerbated the effects of Hurricane Katrina. The Fifth Circuit held that there was no exclusive commitment of the common law issues raised in plaintiffs' complaint to a coordinate branch of government and that no initial policy determination was required to adjudicate these claims. The court granted petitions for rehearing. An additional recusal left the Fifth Circuit without a quorum to reconsider the decision and the appeal was dismissed, leaving the district court's decision in place. Plaintiffs filed a petition with the U.S. Supreme Court asking the court to remand the case to the Fifth Circuit and reinstate the panel decision. The petition was denied in January 2011. Plaintiffs refiled their complaint in federal district court. The court ordered all defendants to respond to the refiled complaints in October 2011 and set a status conference for December 1, 2011. Management believes the claims are without merit, and in addition to other defenses, are barred by the doctrine of collateral estoppel and the applicable statute of limitations. Management intends to vigorously defend against the claims. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

Alaskan Villages' Claims

In 2008, the Native Village of Kivalina and the City of Kivalina, Alaska filed a lawsuit in Federal Court in the Northern District of California against AEP, AEPSC and 22 other unrelated defendants including oil and gas companies, a coal company and other electric generating companies. The complaint alleges that the defendants' emissions of CO_2 contribute to global warming and constitute a public and private nuisance and that the defendants are acting together. The complaint further alleges that some of the defendants, including AEP, conspired to create a false scientific debate about global warming in order to deceive the public and perpetuate the alleged nuisance. The plaintiffs also allege that the effects of global warming will require the relocation of the village at an alleged cost of $95 million to $400 million. In October 2009, the judge dismissed plaintiffs' federal common law claim for nuisance, finding the claim barred by the political question doctrine and by plaintiffs' lack of standing to bring the claim. The judge also dismissed plaintiffs' state law claims without prejudice to refiling in state court. The plaintiffs appealed the decision. The defendants requested that the court defer setting this case for oral argument until after the Supreme Court issues its decision in the CO_2 public nuisance case discussed above. The court entered an order deferring argument until after June 2011 and the parties requested supplemental briefing on the impact of the Supreme Court's decision. The court has set a November 2011 date for oral argument. Management believes the action is without merit and intends to defend against the claims. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

5. BENEFIT PLANS

KPCo participates in an AEP sponsored qualified pension plan which covers substantially all of KPCo's employees. KPCo also participates in OPEB plans sponsored by AEP to provide medical and life insurance benefits for retired employees.

Components of Net Periodic Benefit Cost

The following tables provide the components of KPCo's net periodic benefit cost for the plans for the three and nine months ended September 30, 2011 and 2010:

	Pension Plan		Other Postretirement Benefit Plans	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2011	2010	2011	2010
	(in thousands)			
Service Cost	$ 347	$ 638	$ 234	$ 265
Interest Cost	1,440	1,475	728	739
Expected Return on Plan Assets	(1,838)	(1,914)	(757)	(711)
Amortization of Transition Obligation	-	-	-	122
Amortization of Prior Service Cost (Credit)	38	38	(9)	-
Amortization of Net Actuarial Loss	737	512	188	183
Net Periodic Benefit Cost	$ 724	$ 749	$ 384	$ 598

	Pension Plan		Other Postretirement Benefit Plans	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(in thousands)			
Service Cost	$ 1,041	$ 1,912	$ 704	$ 795
Interest Cost	4,318	4,425	2,185	2,215
Expected Return on Plan Assets	(5,513)	(5,741)	(2,272)	(2,131)
Amortization of Transition Obligation	-	-	-	366
Amortization of Prior Service Cost (Credit)	113	113	(26)	-
Amortization of Net Actuarial Loss	2,213	1,538	563	549
Net Periodic Benefit Cost	$ 2,172	$ 2,247	$ 1,154	$ 1,794

6. BUSINESS SEGMENTS

KPCo has one reportable segment, an integrated electricity generation, transmission and distribution business. KPCo's other activities are insignificant.

7. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

KPCo is exposed to certain market risks as a major power producer and marketer of wholesale electricity, coal and emission allowances. These risks include commodity price risk, interest rate risk, credit risk and, to a lesser extent, foreign currency exchange risk. These risks represent the risk of loss that may impact KPCo due to changes in the underlying market prices or rates. AEPSC, on behalf of KPCo, manages these risks using derivative instruments.

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Trading Strategies

The strategy surrounding the use of derivative instruments for trading purposes focuses on seizing market opportunities to create value driven by expected changes in the market prices of the commodities in which AEPSC transacts on behalf of KPCo.

Risk Management Strategies

The strategy surrounding the use of derivative instruments focuses on managing risk exposures, future cash flows and creating value utilizing both economic and formal hedging strategies. To accomplish these objectives, AEPSC, on behalf of KPCo, primarily employs risk management contracts including physical forward purchase and sale contracts, financial forward purchase and sale contracts and financial swap instruments. Not all risk management contracts meet the definition of a derivative under the accounting guidance for "Derivatives and Hedging." Derivative risk management contracts elected normal under the normal purchases and normal sales scope exception are not subject to the requirements of this accounting guidance.

AEPSC, on behalf of KPCo, enters into power, coal, natural gas, interest rate and, to a lesser degree, heating oil and gasoline, emission allowance and other commodity contracts to manage the risk associated with the energy business. AEPSC, on behalf of KPCo, enters into interest rate derivative contracts in order to manage the interest rate exposure associated with KPCo's commodity portfolio. For disclosure purposes, such risks are grouped as "Commodity," as these risks are related to energy risk management activities. AEPSC, on behalf of KPCo, also engages in risk management of interest rate risk associated with debt financing and foreign currency risk associated with future purchase obligations denominated in foreign currencies. The amount of risk taken is determined by the Commercial Operations and Finance groups in accordance with the established risk management policies as approved by the Finance Committee of AEP's Board of Directors.

The following table represents the gross notional volume of the KPCo's outstanding derivative contracts as of September 30, 2011 and December 31, 2010:

Notional Volume of Derivative Instruments

	Volume		
	September 30, 2011	**December 31, 2010**	**Unit of Measure**
	(in thousands)		
Commodity:			
Power	44,098	40,277	MWHs
Coal	1,762	3,280	Tons
Natural Gas	1,074	449	MMBtus
Heating Oil and Gasoline	348	274	Gallons
Interest Rate	$ 6,730	$ 2,008	USD

Fair Value Hedging Strategies

AEPSC, on behalf of KPCo, enters into interest rate derivative transactions as part of an overall strategy to manage the mix of fixed-rate and floating-rate debt. Certain interest rate derivative transactions effectively modify KPCo's exposure to interest rate risk by converting a portion of KPCo's fixed-rate debt to a floating rate. Provided specific criteria are met, these interest rate derivatives are designated as fair value hedges.

Cash Flow Hedging Strategies

AEPSC, on behalf of KPCo, enters into and designates as cash flow hedges certain derivative transactions for the purchase and sale of power, coal, natural gas and heating oil and gasoline ("Commodity") in order to manage the variable price risk related to the forecasted purchase and sale of these commodities. Management monitors the potential impacts of commodity price changes and, where appropriate, enters into derivative transactions to protect profit margins for a portion of future electricity sales and fuel or energy purchases. KPCo does not hedge all commodity price risk.

KPCo's vehicle fleet is exposed to gasoline and diesel fuel price volatility. AEPSC, on behalf of KPCo, enters into financial heating oil and gasoline derivative contracts in order mitigate price risk of future fuel purchases. For disclosure purposes, these contracts are included with other hedging activity as "Commodity." KPCo does not hedge all fuel price risk.

AEPSC, on behalf of KPCo, enters into a variety of interest rate derivative transactions in order to manage interest rate risk exposure. Some interest rate derivative transactions effectively modify exposure to interest rate risk by converting a portion of floating-rate debt to a fixed rate. AEPSC, on behalf of KPCo, also enters into interest rate derivative contracts to manage interest rate exposure related to anticipated borrowings of fixed-rate debt. The anticipated fixed-rate debt offerings have a high probability of occurrence as the proceeds will be used to fund existing debt maturities and projected capital expenditures. KPCo does not hedge all interest rate exposure.

At times, KPCo is exposed to foreign currency exchange rate risks primarily when some fixed assets are purchased from foreign suppliers. In accordance with AEP's risk management policy, AEPSC, on behalf of KPCo, may enter into foreign currency derivative transactions to protect against the risk of increased cash outflows resulting from a foreign currency's appreciation against the dollar. KPCo does not hedge all foreign currency exposure.

ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND THE IMPACT ON KPCo's FINANCIAL STATEMENTS

The accounting guidance for "Derivatives and Hedging" requires recognition of all qualifying derivative instruments as either assets or liabilities on the condensed balance sheets at fair value. The fair values of derivative instruments accounted for using MTM accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data and assumptions. In order to determine the relevant fair values of the derivative instruments, KPCo applies valuation adjustments for discounting, liquidity and credit quality.

Credit risk is the risk that a counterparty will fail to perform on the contract or fail to pay amounts due. Liquidity risk represents the risk that imperfections in the market will cause the price to vary from estimated fair value based upon prevailing market supply and demand conditions. Since energy markets are imperfect and volatile, there are inherent risks related to the underlying assumptions in models used to fair value risk management contracts. Unforeseen events may cause reasonable price curves to differ from actual price curves throughout a contract's term and at the time a contract settles. Consequently, there could be significant adverse or favorable effects on future net income and cash flows if market prices are not consistent with management's estimates of current market consensus for forward prices in the current period. This is particularly true for longer term contracts. Cash flows may vary based on market conditions, margin requirements and the timing of settlement of KPCo's risk management contracts.

According to the accounting guidance for "Derivatives and Hedging," KPCo reflects the fair values of derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, KPCo is required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the September 30, 2011 and December 31, 2010 balance sheets, KPCo netted \$297 thousand and \$400 thousand, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and \$1.8 million and \$3.4 million, respectively, of cash collateral paid to third parties against short-term and long-term risk management liabilities.

The following tables represent the gross fair value impact of KPCo's derivative activity on the condensed balance sheets as of September 30, 2011 and December 31, 2010:

Fair Value of Derivative Instruments
September 30, 2011

	Risk Management Contracts	Hedging Contracts			
Balance Sheet Location	**Commodity (a)**	**Commodity (a)**	**Interest Rate (a)**	**Other (b)**	**Total**
		(in thousands)			
Current Risk Management Assets	$ 31,068	$ 385	$ -	$ (25,066)	$ 6,387
Long-term Risk Management Assets	13,359	140	-	(8,377)	5,122
Total Assets	44,427	525	-	(33,443)	11,509
Current Risk Management Liabilities	30,400	448	-	(26,761)	4,087
Long-term Risk Management Liabilities	10,079	92	-	(8,647)	1,524
Total Liabilities	40,479	540	-	(35,408)	5,611
Total MTM Derivative Contract Net Assets (Liabilities)	$ 3,948	$ (15)	$ -	$ 1,965	$ 5,898

Fair Value of Derivative Instruments
December 31, 2010

	Risk Management Contracts	Hedging Contracts			
Balance Sheet Location	**Commodity (a)**	**Commodity (a)**	**Interest Rate (a)**	**Other (b)**	**Total**
		(in thousands)			
Current Risk Management Assets	$ 60,231	$ 418	$ -	$ (51,952)	$ 8,697
Long-term Risk Management Assets	16,978	148	-	(9,096)	8,030
Total Assets	77,209	566	-	(61,048)	16,727
Current Risk Management Liabilities	59,107	490	-	(53,638)	5,959
Long-term Risk Management Liabilities	13,265	146	-	(11,108)	2,303
Total Liabilities	72,372	636	-	(64,746)	8,262
Total MTM Derivative Contract Net Assets (Liabilities)	$ 4,837	$ (70)	$ -	$ 3,698	$ 8,465

(a) Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented on the condensed balance sheets on a net basis in accordance with the accounting guidance for "Derivatives and Hedging."

(b) Amounts include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging." Amounts also include de-designated risk management contracts.

The table below presents KPCo's activity of derivative risk management contracts for the three and nine months ended September 30, 2011 and 2010:

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Three and Nine Months Ended September 30, 2011 and 2010

	Three Months Ended September 30,		Nine Months Ended September 30,	
Location of Gain (Loss)	**2011**	**2010**	**2011**	**2010**
		(in thousands)		
Electric Generation, Transmission and Distribution Revenues	$ 213	$ 2,588	$ 3,199	$ 7,197
Sales to AEP Affiliates	22	(248)	27	(1,004)
Fuel and Other Consumables Used for Electric Generation	(1)	-	(1)	-
Regulatory Assets (a)	43	-	93	-
Regulatory Liabilities (a)	(412)	(1,268)	(301)	(1,334)
Total Gain (Loss) on Risk Management Contracts	$ (135)	$ 1,072	$ 3,017	$ 4,859

(a) Represents realized and unrealized gains and losses subject to regulatory accounting treatment recorded as either current or noncurrent on the condensed balance sheets.

Certain qualifying derivative instruments have been designated as normal purchase or normal sale contracts, as provided in the accounting guidance for "Derivatives and Hedging." Derivative contracts that have been designated as normal purchases or normal sales under that accounting guidance are not subject to MTM accounting treatment and are recognized on the condensed statements of income on an accrual basis.

KPCo's accounting for the changes in the fair value of a derivative instrument depends on whether it qualifies for and has been designated as part of a hedging relationship and further, on the type of hedging relationship. Depending on the exposure, management designates a hedging instrument as a fair value hedge or a cash flow hedge.

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in Revenues on a net basis on KPCo's condensed statements of income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in Revenues or Expenses on KPCo's condensed statements of income depending on the relevant facts and circumstances. However, unrealized and some realized gains and losses for both trading and non-trading derivative instruments are recorded as regulatory assets (for losses) or regulatory liabilities (for gains), in accordance with the accounting guidance for "Regulated Operations."

Accounting for Fair Value Hedging Strategies

For fair value hedges (i.e. hedging the exposure to changes in the fair value of an asset, liability or an identified portion thereof attributable to a particular risk), the gain or loss on the derivative instrument as well as the offsetting gain or loss on the hedged item associated with the hedged risk affects Net Income during the period of change.

KPCo records realized and unrealized gains or losses on interest rate swaps that qualify for fair value hedge accounting treatment and any offsetting changes in the fair value of the debt being hedged in Interest Expense on KPCo's condensed statements of income. During the three and nine months ended September 30, 2011 and 2010, KPCo did not employ any fair value hedging strategies.

Accounting for Cash Flow Hedging Strategies

For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows that is attributable to a particular risk), KPCo initially reports the effective portion of the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income (Loss) on the condensed balance sheets until the period the hedged item affects Net Income. KPCo recognizes any hedge ineffectiveness as a regulatory asset (for losses) or a regulatory liability (for gains).

Realized gains and losses on derivatives contracts for the purchase and sale of power, coal, natural gas and heating oil and gasoline designated as cash flow hedges are included in Revenues, Fuel and Other Consumables Used for Electric Generation or Purchased Electricity for Resale on KPCo's condensed statements of income, or in Regulatory Assets or Regulatory Liabilities on KPCo's condensed balance sheets, depending on the specific nature of the risk being hedged. During the three and nine months ended September 30, 2011 and 2010, KPCo designated commodity derivatives as cash flow hedges.

KPCo reclassifies gains and losses on financial fuel derivative contracts designated as cash flow hedges from Accumulated Other Comprehensive Income (Loss) on its condensed balance sheets into Other Operation expense, Maintenance expense or Depreciation and Amortization expense, as it relates to capital projects, on the condensed statements of income. During the three and nine months ended September 30, 2011 and 2010, KPCo designated heating oil and gasoline derivatives as cash flow hedges.

KPCo reclassifies gains and losses on interest rate derivative hedges related to debt financings from Accumulated Other Comprehensive Income (Loss) into Interest Expense in those periods in which hedged interest payments occur. During the three and nine months ended September 30, 2011 and 2010, KPCo did not designate any cash flow hedging strategies for interest rate derivative hedges.

The accumulated gains or losses related to foreign currency hedges are reclassified from Accumulated Other Comprehensive Income (Loss) on KPCo's condensed balance sheets into Depreciation and Amortization expense on the condensed statements of income over the depreciable lives of the fixed assets that were designated as the hedged items in qualifying foreign currency hedging relationships. During the three and nine months ended September 30, 2011 and 2010, KPCo did not employ any foreign currency hedges.

During the three and nine months ended September 30, 2011 and 2010, hedge ineffectiveness was immaterial or nonexistent for all hedge strategies disclosed above.

The following tables provide details on designated, effective cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's condensed balance sheets and the reasons for changes in cash flow hedges for the three and nine months ended September 30, 2011 and 2010. All amounts in the following tables are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
For the Three Months Ended September 30, 2011

	Commodity	Interest Rate	Total
		(in thousands)	
Balance in AOCI as of June 30, 2011	$ 153	$ (373)	$ (220)
Changes in Fair Value Recognized in AOCI	(151)	-	(151)
Amount of (Gain) or Loss Reclassified from AOCI to Income Statement/within Balance Sheet:			
Electric Generation, Transmission and Distribution Revenues	35	-	35
Purchased Electricity for Resale	(29)	-	(29)
Other Operation Expense	(10)	-	(10)
Maintenance Expense	(11)	-	(11)
Interest Expense	-	16	16
Property, Plant and Equipment	(14)	-	(14)
Regulatory Assets (a)	9	-	9
Regulatory Liabilities (a)	-	-	-
Balance in AOCI as of September 30, 2011	$ (18)	$ (357)	$ (375)

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
For the Three Months Ended September 30, 2010

	Commodity	Interest Rate	Total
		(in thousands)	
Balance in AOCI as of June 30, 2010	$ (301)	$ (433)	$ (734)
Changes in Fair Value Recognized in AOCI	(244)	-	(244)
Amount of (Gain) or Loss Reclassified from AOCI to Income Statement/within Balance Sheet:			
Electric Generation, Transmission and Distribution Revenues	59	-	59
Purchased Electricity for Resale	55	-	55
Other Operation Expense	(2)	-	(2)
Maintenance Expense	(3)	-	(3)
Interest Expense	-	15	15
Property, Plant and Equipment	(3)	-	(3)
Regulatory Assets (a)	-	-	-
Regulatory Liabilities (a)	-	-	-
Balance in AOCI as of September 30, 2010	$ (439)	$ (418)	$ (857)

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
For the Nine Months Ended September 30, 2011

	Commodity	Interest Rate	Total
		(in thousands)	
Balance in AOCI as of December 31, 2010	$ (48)	$ (403)	$ (451)
Changes in Fair Value Recognized in AOCI	(111)	-	(111)
Amount of (Gain) or Loss Reclassified from AOCI			
to Income Statement/within Balance Sheet:			
Electric Generation, Transmission and Distribution Revenues	207	-	207
Purchased Electricity for Resale	17	-	17
Other Operation Expense	(26)	-	(26)
Maintenance Expense	(31)	-	(31)
Interest Expense	-	46	46
Property, Plant and Equipment	(35)	-	(35)
Regulatory Assets (a)	9	-	9
Regulatory Liabilities (a)	-	-	-
Balance in AOCI as of September 30, 2011	$ (18)	$ (357)	$ (375)

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
For the Nine Months Ended September 30, 2010

	Commodity	Interest Rate	Total
		(in thousands)	
Balance in AOCI as of December 31, 2009	$ (138)	$ (463)	$ (601)
Changes in Fair Value Recognized in AOCI	(641)	-	(641)
Amount of (Gain) or Loss Reclassified from AOCI			
to Income Statement/within Balance Sheet:			
Electric Generation, Transmission and Distribution Revenues	113	-	113
Purchased Electricity for Resale	260	-	260
Other Operation Expense	(9)	-	(9)
Maintenance Expense	(12)	-	(12)
Interest Expense	-	45	45
Property, Plant and Equipment	(12)	-	(12)
Regulatory Assets (a)	-	-	-
Regulatory Liabilities (a)	-	-	-
Balance in AOCI as of September 30, 2010	$ (439)	$ (418)	$ (857)

(a) Represents realized and unrealized gains and losses subject to regulatory accounting treatment recorded as either current or noncurrent on the condensed balance sheets.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's condensed balance sheets at September 30, 2011 and December 31, 2010 were:

Impact of Cash Flow Hedges on the Condensed Balance Sheet
September 30, 2011

	Commodity	Interest Rate	Total
		(in thousands)	
Hedging Assets (a)	$ 172	$ -	$ 172
Hedging Liabilities (a)	187	-	187
AOCI Loss Net of Tax	(18)	(357)	(375)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	(52)	(60)	(112)

Impact of Cash Flow Hedges on the Condensed Balance Sheet
December 31, 2010

	Commodity	Interest Rate	Total
		(in thousands)	
Hedging Assets (a)	$ 81	$ -	$ 81
Hedging Liabilities (a)	151	-	151
AOCI Loss Net of Tax	(48)	(403)	(451)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	(48)	(60)	(108)

(a) Hedging Assets and Hedging Liabilities are included in Risk Management Assets and Liabilities on KPCo's condensed balance sheets.

The actual amounts that KPCo reclassifies from Accumulated Other Comprehensive Income (Loss) to Net Income can differ from the estimate above due to market price changes. As of September 30, 2011, the maximum length of time that KPCo is hedging (with contracts subject to the accounting guidance for "Derivatives and Hedging") exposure to variability in future cash flows related to forecasted transactions is 32 months.

Credit Risk

AEPSC, on behalf of KPCo, limits credit risk in KPCo's wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. AEPSC, on behalf of KPCo, uses Moody's, Standard and Poor's and current market-based qualitative and quantitative data as well as financial statements to assess the financial health of counterparties on an ongoing basis.

AEPSC, on behalf of KPCo, uses standardized master agreements which may include collateral requirements. These master agreements facilitate the netting of cash flows associated with a single counterparty. Cash, letters of credit and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. The collateral agreements require a counterparty to post cash or letters of credit in the event an exposure exceeds the established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with AEP's credit policy. In addition, collateral agreements allow for termination and liquidation of all positions in the event of a failure or inability to post collateral.

Collateral Triggering Events

Under the tariffs of the RTOs and Independent System Operators (ISOs) and a limited number of derivative and non-derivative contracts primarily related to competitive retail auction loads, KPCo is obligated to post an additional amount of collateral if certain credit ratings decline below investment grade. The amount of collateral required fluctuates based on market prices and total exposure. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these collateral triggering items in contracts. Management does not anticipate a downgrade below investment grade. The following table represents: (a) the aggregate fair value of such derivative contracts, (b) the amount of collateral KPCo would have been required to post for all derivative and non-derivative contracts if the credit ratings had declined below investment grade and (c) how much was attributable to RTO and ISO activities as of September 30, 2011 and December 31, 2010:

	September 30, 2011	December 31, 2010
	(in thousands)	
Liabilities for Derivative Contracts with Credit Downgrade Triggers	$ 2,037	$ 1,368
Amount of Collateral KPCo Would Have Been Required to Post	2,481	2,614
Amount Attributable to RTO and ISO Activities	2,481	2,608

As of September 30, 2011 and December 31, 2010, KPCo was not required to post any collateral.

In addition, a majority of KPCo's non-exchange traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event by Parent or the obligor under outstanding debt or a third party obligation in excess of $50 million. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-default provisions in the contracts. Management does not anticipate a non-performance event under these provisions. The following table represents: (a) the fair value of these derivative liabilities subject to cross-default provisions prior to consideration of contractual netting arrangements, (b) the amount this exposure has been reduced by cash collateral posted by KPCo and (c) if a cross-default provision would have been triggered, the settlement amount that would be required after considering KPCo's contractual netting arrangements as of September 30, 2011 and December 31, 2010:

	September 30, 2011	December 31, 2010
	(in thousands)	
Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	$ 9,337	$ 15,930
Amount of Cash Collateral Posted	115	1,376
Additional Settlement Liability if Cross Default Provision is Triggered	3,275	4,926

8. FAIR VALUE MEASUREMENTS

Fair Value Hierarchy and Valuation Techniques

The accounting guidance for "Fair Value Measurements and Disclosures" establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. When quoted market prices are not available, pricing may be completed using comparable securities, dealer values, operating data and general market conditions to determine fair value. Valuation models utilize various inputs such as commodity, interest rate and, to a lesser degree, volatility and credit that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability.

For commercial activities, exchange traded derivatives, namely futures contracts, are generally fair valued based on unadjusted quoted prices in active markets and are classified as Level 1. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, as well as exchange traded contracts where there is insufficient market liquidity to warrant inclusion in Level 1. Management verifies price curves using these broker quotes and classifies these fair values within Level 2 when substantially all of the fair value can be corroborated. Management typically obtains multiple broker quotes, which are non-binding in nature, but are based on recent trades in the marketplace. When multiple broker quotes are obtained, the quoted bid and ask prices are averaged. In certain circumstances, a broker quote may be discarded if it is a clear outlier. Management uses a historical correlation analysis between the broker quoted location and the illiquid locations. If the points are highly correlated, these locations are included within Level 2 as well. Certain OTC and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. Long-dated and illiquid complex or structured transactions and FTRs can introduce the need for internally developed modeling inputs based upon extrapolations and assumptions of observable market data to estimate fair value. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized as Level 3.

Fair Value Measurements of Long-term Debt

The fair values of Long-term Debt are based on quoted market prices, without credit enhancements, for the same or similar issues and the current interest rates offered for instruments with similar maturities. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that could be realized in a current market exchange.

The book values and fair values of KPCo's Long-term Debt as of September 30, 2011 and December 31, 2010 are summarized in the following table:

	September 30, 2011		December 31, 2010	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
Long-term Debt	$ 549,013	$ 678,747	$ 548,888	$ 628,623

Fair Value Measurements of Financial Assets and Liabilities

The following tables set forth, by level within the fair value hierarchy, KPCo's financial assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2011 and December 31, 2010. As required by the accounting guidance for "Fair Value Measurements and Disclosures," financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There have not been any significant changes in management's valuation techniques.

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2011

	Level 1	Level 2	Level 3	Other	Total
			(in thousands)		
Assets:					
Risk Management Assets					
Risk Management Commodity Contracts (a) (c)	$ 342	$ 39,248	$ 2,783	$ (31,502)	$ 10,871
Cash Flow Hedges:					
Commodity Hedges (a)	-	517	-	(345)	172
De-designated Risk Management Contracts (b)	-	-	-	466	466
Total Risk Management Assets	$ 342	$ 39,765	$ 2,783	$ (31,381)	$ 11,509
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (c)	$ 204	$ 35,609	$ 2,612	$ (33,001)	$ 5,424
Cash Flow Hedges:					
Commodity Hedges (a)	-	522	10	(345)	187
Total Risk Management Liabilities	$ 204	$ 36,131	$ 2,622	$ (33,346)	$ 5,611

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2010

	Level 1	Level 2	Level 3	Other	Total
			(in thousands)		
Assets:					
Risk Management Assets					
Risk Management Commodity Contracts (a) (c)	$ 350	$ 73,753	$ 2,862	$ (61,018)	$ 15,947
Cash Flow Hedges:					
Commodity Hedges (a)	-	549	-	(468)	81
De-designated Risk Management Contracts (b)	-	-	-	699	699
Total Risk Management Assets	$ 350	$ 74,302	$ 2,862	$ (60,787)	$ 16,727
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (c)	$ 343	$ 69,996	$ 1,789	$ (64,017)	$ 8,111
Cash Flow Hedges:					
Commodity Hedges (a)	-	619	-	(468)	151
Total Risk Management Liabilities	$ 343	$ 70,615	$ 1,789	$ (64,485)	$ 8,262

(a) Amounts in "Other" column primarily represent counterparty netting of risk management and hedging contracts and associated cash collateral under the accounting guidance for "Derivatives and Hedging."
(b) Represents contracts that were originally MTM but were subsequently elected as normal under the accounting guidance for "Derivatives and Hedging." At the time of the normal election, the MTM value was frozen and no longer fair valued. This MTM value will be amortized into revenues over the remaining life of the contracts.
(c) Substantially comprised of power contracts.

There were no transfers between Level 1 and Level 2 during the three and nine months ended September 30, 2011 and 2010.

The following tables set forth a reconciliation of changes in the fair value of net trading derivatives and other investments classified as Level 3 in the fair value hierarchy:

Three Months Ended September 30, 2011		Net Risk Management Assets (Liabilities) (in thousands)
Balance as of June 30, 2011	$	1,127
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)		(963)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)		-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income		(1)
Purchases, Issuances and Settlements (c)		76
Transfers into Level 3 (d) (f)		-
Transfers out of Level 3 (e) (f)		(55)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)		(23)
Balance as of September 30, 2011	$	161

Three Months Ended September 30, 2010		Net Risk Management Assets (Liabilities) (in thousands)
Balance as of June 30, 2010	$	2,254
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)		(338)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)		-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income		-
Purchases, Issuances and Settlements (c)		40
Transfers into Level 3 (d) (f)		79
Transfers out of Level 3 (e) (f)		(185)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)		1,584
Balance as of September 30, 2010	$	3,434

Nine Months Ended September 30, 2011		Net Risk Management Assets (Liabilities) (in thousands)
Balance as of December 31, 2010	$	1,073
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)		(501)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)		-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income		(10)
Purchases, Issuances and Settlements (c)		603
Transfers into Level 3 (d) (f)		272
Transfers out of Level 3 (e) (f)		(635)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)		(641)
Balance as of September 30, 2011	$	161

Nine Months Ended September 30, 2010	Net Risk Management Assets (Liabilities)
	(in thousands)
Balance as of December 31, 2009	$ 1,899
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	278
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-
Purchases, Issuances and Settlements (c)	(1,144)
Transfers into Level 3 (d) (f)	202
Transfers out of Level 3 (e) (f)	(435)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	2,634
Balance as of September 30, 2010	$ 3,434

(a) Included in revenues on KPCo's condensed statements of income.
(b) Represents the change in fair value between the beginning of the reporting period and the settlement of the risk management commodity contract.
(c) Represents the settlement of risk management commodity contracts for the reporting period.
(d) Represents existing assets or liabilities that were previously categorized as Level 2.
(e) Represents existing assets or liabilities that were previously categorized as Level 3.
(f) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.
(g) Relates to the net gains (losses) of those contracts that are not reflected on KPCo's condensed statements of income. These net gains (losses) are recorded as regulatory assets/liabilities.

9. INCOME TAXES

KPCo joins in the filing of a consolidated federal income tax return with its affiliates in the AEP System. The allocation of the AEP System's current consolidated federal income tax to the AEP System companies allocates the benefit of current tax losses to the AEP System companies giving rise to such losses in determining their current tax expense. The tax benefit of the Parent is allocated to its subsidiaries with taxable income. With the exception of the loss of the Parent, the method of allocation reflects a separate return result for each company in the consolidated group.

KPCo and other AEP subsidiaries are no longer subject to U.S. federal examination for years before 2009. KPCo and other AEP subsidiaries completed the examination of the years 2007 and 2008 in April 2011 and settled all outstanding issues on appeal for the years 2001 through 2006 in October 2011. The settlements will not have a material impact on KPCo and other AEP subsidiaries' net income, cash flows or financial condition. The IRS examination of years 2009 and 2010 started in October 2011. Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for federal income taxes have been made for potential liabilities resulting from such matters. In addition, KPCo accrues interest on these uncertain tax positions. Management is not aware of any issues for open tax years that upon final resolution are expected to have a material effect on net income.

KPCo and other AEP subsidiaries file income tax returns in various state and local jurisdictions. These taxing authorities routinely examine the tax returns and KPCo and other AEP subsidiaries are currently under examination in several state and local jurisdictions. Management believes that previously filed tax returns have positions that may be challenged by these tax authorities. However, management believes that adequate provisions for income taxes have been made for potential liabilities resulting from such challenges and that the ultimate resolution of these audits will not materially impact net income. With few exceptions, KPCo is no longer subject to state or local income tax examinations by tax authorities for years before 2000.

Federal Legislation

The Patient Protection and Affordable Care Act and the related Health Care and Education Reconciliation Act (Health Care Acts) were enacted in March 2010. The Health Care Acts amend tax rules so that the portion of employer health care costs that are reimbursed by the Medicare Part D prescription drug subsidy will no longer be deductible by the employer for federal income tax purposes effective for years beginning after December 31, 2012.

Because of the loss of the future tax deduction, a reduction in the deferred tax asset related to the nondeductible OPEB liabilities accrued to date was recorded by KPCo in March 2010. This reduction, which was offset by recording net tax regulatory assets, did not materially affect KPCo's net income, cash flows or financial condition.

The Small Business Jobs Act (the Act) was enacted in September 2010. Included in the Act was a one-year extension of the 50% bonus depreciation provision. The Tax Relief, Unemployment Insurance Reauthorization and the Job Creation Act of 2010 extended the life of research and development, employment and several energy tax credits originally scheduled to expire at the end of 2010. In addition, the Act extended the time for claiming bonus depreciation and increased the deduction to 100% for part of 2010 and 2011. The enacted provisions will not have a material impact on KPCo's net income or financial condition.

State Tax Legislation

Michigan repealed its Business Tax regime in May 2011 and replaced it with a traditional corporate net income tax with a rate of 6%. During the third quarter of 2011, the state of West Virginia determined that the state had achieved certain minimum levels of shortfall reserve funds and thus, the West Virginia corporate income tax rate will be reduced to 7.75% in 2012. The enacted provisions will not have a material impact on KPCo's net income, cash flows or financial condition.

10. FINANCING ACTIVITIES

Long-term Debt

KPCo did not have any long-term debt issuances or retirements during the first nine months of 2011.

Dividend Restrictions

Federal Power Act

The Federal Power Act prohibits KPCo from participating "in the making or paying of any dividends of such public utility from any funds properly included in capital account." The term "capital account" is not defined in the Federal Power Act or its regulations. Management understands "capital account" to mean the par value of the common stock multiplied by the number of shares outstanding. This restriction does not limit the ability of KPCo to pay dividends out of retained earnings.

Utility Money Pool – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of its subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds the utility subsidiaries. The AEP System Utility Money Pool operates in accordance with the terms and conditions approved in a regulatory order. The amount of outstanding loans to the Utility Money Pool as of September 30, 2011 and December 31, 2010 is included in Advances to Affiliates on KPCo's balance sheets. KPCo's Utility Money Pool activity and corresponding authorized borrowing limits for the nine months ended September 30, 2011 are described in the following table:

Maximum Borrowings from Utility Money Pool	Maximum Loans to Utility Money Pool	Average Borrowings from Utility Money Pool	Average Loans to Utility Money Pool	Loans to Utility Money Pool as of September 30, 2011	Authorized Short-Term Borrowing Limit
		(in thousands)			
$ -	$ 117,473	$ -	$ 90,219	$ 95,669	$ 250,000

Maximum, minimum and average interest rates for funds either borrowed from or loaned to the Utility Money Pool for the nine months ended September 30, 2011 and 2010 are summarized in the following table:

Year	Maximum Interest Rates for Funds Borrowed from Utility Money Pool	Minimum Interest Rates for Funds Borrowed from Utility Money Pool	Maximum Interest Rates for Funds Loaned to Utility Money Pool	Minimum Interest Rates for Funds Loaned to Utility Money Pool	Average Interest Rates for Funds Borrowed from Utility Money Pool	Average Interest Rates for Funds Loaned to Utility Money Pool
2011	- %	- %	0.56 %	0.06 %	- %	0.32 %
2010	0.55 %	0.09 %	0.43 %	0.09 %	0.38 %	0.23 %

Sale of Receivables – AEP Credit

Under a sale of receivables arrangement, KPCo sells, without recourse, certain of its customer accounts receivable and accrued unbilled revenue balances to AEP Credit and is charged a fee based on AEP Credit's financing costs, administrative costs and uncollectible accounts experience for KPCo's receivables. The costs of customer accounts receivable sold are reported in Other Operation on KPCo's income statement. KPCo manages and services its accounts receivable sold.

In July 2011, AEP Credit renewed its receivables securitization agreement. The agreement provides commitments of $750 million from bank conduits to finance receivables from AEP Credit with an increase to $800 million for the months of July, August and September to accommodate seasonal demand. A commitment of $375 million, with the seasonal increase to $425 million for the months of July, August and September, expires in June 2012 and the remaining commitment of $375 million expires in June 2014.

KPCo's amount of accounts receivable and accrued unbilled revenues sold under the sale of receivables agreement was $45 million and $63 million as of September 30, 2011 and December 31, 2010, respectively.

The fees paid by KPCo to AEP Credit for customer accounts receivable sold were $586 thousand and $1.7 million for the three and nine months ended September 30, 2011, respectively, and $569 thousand and $1.7 million for the three and nine months ended September 30, 2010, respectively.

KPCo's proceeds on the sale of receivables to AEP Credit were $139 million and $441 million for the three and nine months ended September 30, 2011, respectively, and $141 million and $399 million for the three and nine months ended September 30, 2010, respectively.

11. COST REDUCTION INITIATIVES

In April 2010, management began initiatives to decrease both labor and non-labor expenses with a goal of achieving significant reductions in operation and maintenance expenses. A total of 2,461 positions was eliminated across the AEP System as a result of process improvements, streamlined organizational designs and other efficiencies. Most of the affected employees terminated employment May 31, 2010. The severance program provided two weeks of base pay for every year of service along with other severance benefits.

KPCo recorded a charge to Other Operation expense during the second quarter of 2010 primarily related to severance benefits as the result of headcount reduction initiatives. The total amount incurred in 2010 by KPCo was $11.7 million.

KPCo's cost reduction activity for the nine months ended September 30, 2011 is described in the following table:

Balance at December 31, 2010	Incurred	Settled	Adjustments	Balance at September 30, 2011
		(in thousands)		
$ 1,018	$ -	$ (437)	$ (301)	$ 280

The remaining accrual is included in Other Current Liabilities on the condensed balance sheets.

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Kentucky Power Company

2010 Annual Report

Financial Statements

AEP AMERICAN® ELECTRIC POWER

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GLOSSARY OF TERMS

When the following terms and abbreviations appear in the text of this report, they have the meanings indicated below.

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP or Parent	American Electric Power Company, Inc.
AEP Credit	AEP Credit, Inc., a subsidiary of AEP which factors accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP East companies	APCo, CSPCo, I&M, KPCo and OPCo.
AEPES	AEP Energy Services, Inc., a subsidiary of AEP Resources, Inc.
AEPSC	American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries.
AEP System or the System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEP Power Pool	Members are APCo, CSPCo, I&M, KPCo and OPCo. The Pool shares the generation, cost of generation and resultant wholesale off-system sales of the member companies.
AEP West companies	PSO, SWEPCo, TCC and TNC.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
CO_2	Carbon Dioxide and other greenhouse gases.
CSPCo	Columbus Southern Power Company, an AEP electric utility subsidiary.
CSW	Central and South West Corporation, a subsidiary of AEP (Effective January 21, 2003, the legal name of Central and South West Corporation was changed to AEP Utilities, Inc.).
CSW Operating Agreement	Agreement, dated January 1, 1997, as amended, by and among PSO and SWEPCo governing generating capacity allocation. AEPSC acts as the agent.
CWIP	Construction Work in Progress.
DETM	Duke Energy Trading and Marketing L.L.C., a risk management counterparty.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company.
ERCOT	Electric Reliability Council of Texas.
FAC	Fuel Adjustment Clause.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
KGPCo	Kingsport Power Company, an AEP electric distribution subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
kV	Kilovolt.
MISO	Midwest Independent Transmission System Operator.
MMBtus	Million British Thermal Units.
MLR	Member load ratio, the method used to allocate AEP Power Pool transactions to its members.
MTM	Mark-to-Market.
MW	Megawatt.
NO_x	Nitrogen oxide.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefit Plans.
OTC	Over the counter.
OVEC	Ohio Valley Electric Corporation, which is 43.47% owned by AEP.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.

Term	Meaning
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generating plant, consisting of two 1,300 MW coal-fired generating units near Rockport, Indiana.
RTO	Regional Transmission Organization.
SIA	System Integration Agreement.
SO_2	Sulfur Dioxide.
SPP	Southwest Power Pool.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
Utility Money Pool	AEP System's Utility Money Pool.
VIE	Variable Interest Entity.
WPCo	Wheeling Power Company, an AEP electric distribution subsidiary.

INDEPENDENT AUDITORS' REPORT

To the Board of Directors and Shareholder of
Kentucky Power Company:

We have audited the accompanying balance sheets of Kentucky Power Company (the "Company") as of December 31, 2010 and 2009, and the related statements of income, changes in common shareholder's equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2010. 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 as established by the Auditing Standards Board (United States) and in accordance with the auditing standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, 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 financial statements present fairly, in all material respects, the financial position of Kentucky Power Company as of December 31, 2010 and 2009, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2010 in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 25, 2011

KENTUCKY POWER COMPANY
STATEMENTS OF INCOME
For the Years Ended December 31, 2010, 2009 and 2008
(in thousands)

	2010	2009	2008
REVENUES			
Electric Generation, Transmission and Distribution	$ 623,100	$ 567,564	$ 597,699
Sales to AEP Affiliates	60,005	62,613	66,249
Other Revenues	567	2,349	1,612
TOTAL REVENUES	683,672	632,526	665,560
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	185,938	188,525	171,215
Purchased Electricity for Resale	21,422	24,839	26,157
Purchased Electricity from AEP Affiliates	208,400	198,320	234,379
Other Operation	68,972	51,417	64,330
Maintenance	46,223	38,888	47,921
Depreciation and Amortization	52,867	52,010	48,067
Taxes Other Than Income Taxes	10,995	11,738	9,644
TOTAL EXPENSES	594,817	565,737	601,713
OPERATING INCOME	88,855	66,789	63,847
Other Income (Expense):			
Interest Income	239	218	2,103
Allowance for Equity Funds Used During Construction	768	391	1,012
Interest Expense	(36,442)	(33,812)	(34,535)
INCOME BEFORE INCOME TAX EXPENSE	53,420	33,586	32,427
Income Tax Expense	18,138	9,650	7,896
NET INCOME	$ 35,282	$ 23,936	$ 24,531

The common stock of KPCo is wholly-owned by AEP.

See Notes to Financial Statements.

KENTUCKY POWER COMPANY
STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2010, 2009 and 2008
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2007	$ 50,450	$ 208,750	$ 128,583	$ (814)	$ 386,969
Adoption of Guidance for Split-Dollar Life Insurance Accounting, Net of Tax of $197			(365)		(365)
Common Stock Dividends			(14,000)		(14,000)
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					372,604
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $470				873	873
NET INCOME			24,531		24,531
TOTAL COMPREHENSIVE INCOME					25,404
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2008	50,450	208,750	138,749	59	398,008
Capital Contribution from Parent		30,000			30,000
Common Stock Dividends			(19,500)		(19,500)
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					408,508
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $355				(660)	(660)
NET INCOME			23,936		23,936
TOTAL COMPREHENSIVE INCOME					23,276
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2009	50,450	238,750	143,185	(601)	431,784
Common Stock Dividends			(21,000)		(21,000)
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					410,784
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $81				150	150
NET INCOME			35,282		35,282
TOTAL COMPREHENSIVE INCOME					35,432
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2010	$ 50,450	$ 238,750	$ 157,467	$ (451)	$ 446,216

See Notes to Financial Statements.

KENTUCKY POWER COMPANY
BALANCE SHEETS
ASSETS
December 31, 2010 and 2009
(in thousands)

	2010	2009
CURRENT ASSETS		
Cash and Cash Equivalents	$ 281	$ 494
Advances to Affiliates	67,060	-
Accounts Receivable:		
Customers	21,652	17,593
Affiliated Companies	17,616	8,692
Accrued Unbilled Revenues	3,823	4,806
Miscellaneous	587	1,304
Allowance for Uncollectible Accounts	(623)	(851)
Total Accounts Receivable	43,055	31,544
Fuel	16,640	36,168
Materials and Supplies	24,378	18,248
Risk Management Assets	8,697	13,687
Accrued Tax Benefits	1,420	29,540
Margin Deposits	5,357	5,925
Prepayments and Other Current Assets	1,497	2,416
TOTAL CURRENT ASSETS	168,385	138,022
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	553,589	547,378
Transmission	444,303	438,775
Distribution	590,606	569,389
Other Property, Plant and Equipment	63,982	59,002
Construction Work in Progress	34,093	28,409
Total Property, Plant and Equipment	1,686,573	1,642,953
Accumulated Depreciation and Amortization	542,443	508,806
TOTAL PROPERTY, PLANT AND EQUIPMENT - NET	1,144,130	1,134,147
OTHER NONCURRENT ASSETS		
Regulatory Assets	213,593	206,074
Long-term Risk Management Assets	8,030	9,498
Deferred Charges and Other Noncurrent Assets	37,946	40,178
TOTAL OTHER NONCURRENT ASSETS	259,569	255,750
TOTAL ASSETS	$ 1,572,084	$ 1,527,919

See Notes to Financial Statements.

KENTUCKY POWER COMPANY
BALANCE SHEETS
LIABILITIES AND SHAREHOLDER'S EQUITY
December 31, 2010 and 2009

	2010	2009
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ -	$ 485
Accounts Payable:		
General	33,334	42,595
Affiliated Companies	45,790	27,341
Risk Management Liabilities	5,959	5,190
Customer Deposits	19,692	18,258
Accrued Taxes	23,741	12,625
Accrued Interest	7,570	7,466
Other Current Liabilities	26,227	26,996
TOTAL CURRENT LIABILITIES	162,313	140,956
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	528,888	528,722
Long-term Debt – Affiliated	20,000	20,000
Long-term Risk Management Liabilities	2,303	4,101
Deferred Income Taxes	316,389	304,549
Regulatory Liabilities and Deferred Investment Tax Credits	34,991	35,678
Employee Benefits and Pension Obligations	49,298	49,843
Deferred Credits and Other Noncurrent Liabilities	11,686	12,286
TOTAL NONCURRENT LIABILITIES	963,555	955,179
TOTAL LIABILITIES	1,125,868	1,096,135
Rate Matters (Note 2)		
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $50 Per Share:		
Authorized – 2,000,000 Shares		
Outstanding – 1,009,000 Shares	50,450	50,450
Paid-in Capital	238,750	238,750
Retained Earnings	157,467	143,185
Accumulated Other Comprehensive Income (Loss)	(451)	(601)
TOTAL COMMON SHAREHOLDER'S EQUITY	446,216	431,784
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$ 1,572,084	$ 1,527,919

See Notes to Financial Statements.

KENTUCKY POWER COMPANY
STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2010, 2009 and 2008
(in thousands)

	2010	2009	2008
OPERATING ACTIVITIES			
Net Income	$ 35,282	$ 23,936	$ 24,531
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	52,867	52,010	48,067
Deferred Income Taxes	1,075	50,612	4,097
Deferral of Storm Costs	-	(24,355)	-
Allowance for Equity Funds Used During Construction	(768)	(391)	(1,012)
Mark-to-Market of Risk Management Contracts	5,651	(2,386)	(4,650)
Pension Contributions to Qualified Plan Trust	(6,184)	-	-
Fuel Over/Under-Recovery, Net	(923)	11,740	(5,528)
Change in Other Noncurrent Assets	7,084	1,452	(11,298)
Change in Other Noncurrent Liabilities	(4,619)	(2,943)	2,055
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	(12,035)	(444)	8,317
Fuel, Materials and Supplies	14,512	(13,643)	(18,866)
Accounts Payable	11,228	(7,149)	21,288
Accrued Taxes, Net	37,721	(29,470)	(4,199)
Other Current Assets	1,514	(1,177)	(3,953)
Other Current Liabilities	1,198	(2,997)	2,473
Net Cash Flows from Operating Activities	143,603	54,795	61,322
INVESTING ACTIVITIES			
Construction Expenditures	(54,058)	(63,963)	(129,619)
Change in Advances to Affiliates, Net	(67,060)	-	-
Acquisitions of Assets	(254)	(316)	(314)
Proceeds from Sales of Assets	700	927	947
Net Cash Flows Used for Investing Activities	(120,672)	(63,352)	(128,986)
FINANCING ACTIVITIES			
Capital Contribution from Parent	-	30,000	-
Issuance of Long-term Debt – Nonaffiliated	-	129,292	-
Change in Advances from Affiliates, Net	(485)	(130,914)	112,246
Retirement of Long-term Debt – Nonaffiliated	-	-	(30,000)
Principal Payments for Capital Lease Obligations	(1,674)	(749)	(806)
Dividends Paid on Common Stock	(21,000)	(19,500)	(14,000)
Other Financing Activities	15	276	143
Net Cash Flows from (Used for) Financing Activities	(23,144)	8,405	67,583
Net Decrease in Cash and Cash Equivalents	(213)	(152)	(81)
Cash and Cash Equivalents at Beginning of Period	494	646	727
Cash and Cash Equivalents at End of Period	$ 281	$ 494	$ 646
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 35,838	$ 37,402	$ 28,602
Net Cash Paid (Received) for Income Taxes	(16,700)	(8,713)	3,554
Noncash Acquisitions Under Capital Leases	4,202	829	544
Construction Expenditures Included in Accounts Payable at December 31,	3,411	5,451	9,662
SIA Refund Included in Accounts Payable at December 31,	-	-	18,526

See Notes to Financial Statements.

INDEX OF NOTES TO FINANCIAL STATEMENTS

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1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

As a public utility, KPCo engages in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 174,000 retail customers in its service territory in eastern Kentucky. KPCo also sells power at wholesale to municipalities.

Originally approved by the FERC in 1951 and subsequently amended in 1951, 1962, 1975, 1979 (twice) and 1980, the Interconnection Agreement establishes the AEP Power Pool which permits the AEP East companies to pool their generation assets on a cost basis. It establishes an allocation method for generating capacity among its members based on relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity revenues. AEP Power Pool members are compensated for their costs of energy delivered to the AEP Power Pool and charged for energy received from the AEP Power Pool. The capacity reserve relationship of the AEP Power Pool members changes as generating assets are added, retired or sold and relative peak demand changes. The AEP Power Pool calculates each member's prior twelve-month peak demand relative to the sum of the peak demands of all members as a basis for sharing revenues and costs. The result of this calculation is the MLR, which determines each member's percentage share of revenues and costs.

In December 2010, each member gave notice to AEPSC and the other AEP Power Pool members of its decision to terminate the Interconnection Agreement effective January 1, 2014 or such other date approved by the FERC, subject to state regulatory input. It is unknown at this time whether the AEP Power Pool will be replaced by a new agreement among some or all of the members, whether individual companies will enter into bilateral or multi-party contracts with each other for power sales and purchases or asset transfers or if each company will choose to operate independently. This decision to terminate is subject to management's ongoing evaluation. The AEP Power Pool members may revoke their notices of termination. If KPCo experiences decreases in revenues or increases in costs as a result of the termination of the AEP Power Pool and is unable to recover the change in revenues and costs through rates, prices or additional sales, it would have an adverse impact on future net income and cash flows.

The AEP East companies are parties to a Transmission Agreement defining how they share the costs associated with their relative ownership of transmission assets. This sharing was based upon each company's MLR until the FERC approved a new Transmission Agreement effective November 1, 2010. The impacts of the new Transmission Agreement will be phased-in for retail rates, adds KGPCo and WPCo as parties to the agreement and changes the allocation method.

Under a unit power agreement with AEGCo, an affiliated company that is not a member of the AEP Power Pool, KPCo purchases 15% of the total output of the 2,600 MW Rockport Plant capacity. Therefore, KPCo purchases 390 MW of Rockport Plant capacity. The unit power agreement expires in December 2022. KPCo pays a demand charge for the right to receive the power, which is payable even if the power is not taken.

Under the SIA, AEPSC allocates physical and financial revenues and expenses from neighboring utilities, power marketers and other power and gas risk management activities based upon the location of such activity, with margins resulting from trading and marketing activities originating in PJM and MISO generally accruing to the benefit of the AEP East companies and trading and marketing activities originating in SPP and ERCOT generally accruing to the benefit of PSO and SWEPCo. Margins resulting from other transactions are allocated among the AEP East companies, PSO and SWEPCo in proportion to the marketing realization directly assigned to each zone for the current month plus the preceding eleven months.

AEPSC conducts power, gas, coal and emission allowance risk management activities on KPCo's behalf. KPCo shares in the revenues and expenses associated with these risk management activities, as described in the preceding paragraph, with the other AEP East companies, PSO and SWEPCo. Power and gas risk management activities are allocated based on the existing power pool agreement and the SIA. KPCo shares in coal and emission allowance risk management activities based on its proportion of fossil fuels burned by the AEP System. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas, coal and emission allowances. The electricity, gas, coal and emission allowance contracts include physical transactions, over-the-counter options and financially-settled swaps and exchange-traded futures and options. AEPSC settles the majority of the physical forward contracts by entering into offsetting contracts.

To minimize the credit requirements and operating constraints when operating within PJM, the AEP East companies as well as KGPCo and WPCo, agreed to a netting of all payment obligations incurred by any of the AEP East companies against all balances due to the AEP East companies, and to hold PJM harmless from actions that any one or more AEP East companies may take with respect to PJM.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

KPCo's rates are regulated by the FERC and the KPSC. The FERC also regulates KPCo's affiliated transactions, including AEPSC intercompany service billings which are generally at cost, under the 2005 Public Utility Holding Company Act and the Federal Power Act. The FERC also has jurisdiction over the issuances and acquisitions of securities of the public utility subsidiaries, the acquisition or sale of certain utility assets and mergers with another electric utility or holding company. For non-power goods and services, the FERC requires that a nonregulated affiliate can bill an affiliated public utility company no more than market while a public utility must bill the higher of cost or market to a nonregulated affiliate. The KPSC also regulates certain intercompany transactions under its affiliate statutes. Both the FERC and state regulatory commissions are permitted to review and audit the relevant books and records of companies within a public utility holding company system.

The FERC regulates wholesale power markets, wholesale power transactions and wholesale transmission operations and rates. KPCo's wholesale power transactions are generally market-based. They are cost-based regulated when KPCo negotiates and files a cost-based contract with the FERC or the FERC determines that KPCo has "market power" in the region where the transaction occurs. KPCo has entered into wholesale power supply contracts with various municipalities that are FERC-regulated, cost-based contracts. These contracts are generally formula rate mechanisms, which are trued up to actual costs annually.

The KPSC regulates all of the distribution operations and rates and retail transmission rates on a cost basis. They also regulate the retail generation/power supply operations and rates.

In addition, the FERC regulates the SIA, the Interconnection Agreement, the System Transmission Integration Agreement, the Transmission Agreement and the AEP System Interim Allowance Agreement, all of which allocate shared system costs and revenues to the utility subsidiaries that are parties to each agreement.

Accounting for the Effects of Cost-Based Regulation

As a rate-regulated electric public utility company, KPCo's financial statements reflect the actions of regulators that result in the recognition of certain revenues and expenses in different time periods than enterprises that are not rate-regulated. In accordance with accounting guidance for "Regulated Operations," KPCo records regulatory assets (deferred expenses) and regulatory liabilities (future revenue reductions or refunds) to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues and income with its passage to customers through the reduction of regulated revenues.

Use of Estimates

The preparation of these financial statements in conformity with accounting principles generally accepted in the United States of America (GAAP) requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. These estimates include but are not limited to inventory valuation, allowance for doubtful accounts, long-lived asset impairment, unbilled electricity revenue, valuation of long-term energy contracts, the effects of regulation, long-lived asset recovery, storm costs, the effects of contingencies and certain assumptions made in accounting for pension and postretirement benefits. The estimates and assumptions used are based upon management's evaluation of the relevant facts and circumstances as of the date of the financial statements. Actual results could ultimately differ from those estimates.

Cash and Cash Equivalents

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

Inventory

Fossil fuel inventories and materials and supplies inventories are carried at average cost.

Accounts Receivable

Customer accounts receivable primarily include receivables from wholesale and retail energy customers, receivables from energy contract counterparties related to risk management activities and customer receivables primarily related to other revenue-generating activities.

Revenue is recognized from electric power sales when power is delivered to customers. To the extent that deliveries have occurred but a bill has not been issued, KPCo accrues and recognizes, as Accrued Unbilled Revenues, an estimate of the revenues for energy delivered since the last billing.

AEP Credit factors accounts receivable on a daily basis, excluding receivables from risk management activities, for KPCo. See "Sale of Receivables – AEP Credit" section of Note 11 for additional information.

Allowance for Uncollectible Accounts

Generally, AEP Credit records bad debt expense related to receivables purchased from KPCo. For customer accounts receivables relating to risk management activities, accounts receivables are reviewed for bad debt reserves at a specific counterparty level basis. For miscellaneous accounts receivable, bad debt expense is recorded for all amounts outstanding 180 days or greater at 100%, unless specifically identified. Miscellaneous accounts receivable items open less than 180 days may be reserved using specific identification for bad debt reserves.

Concentrations of Credit Risk and Significant Customers

KPCo does not have any significant customers that comprise 10% or more of its Operating Revenues as of December 31, 2010.

Management monitors credit levels and the financial condition of KPCo's customers on a continuing basis to minimize credit risk. The KPSC allows recovery in rates for a reasonable level of bad debt costs. Management believes adequate provision for credit loss has been made in the accompanying financial statements.

Emission Allowances

KPCo records emission allowances at cost, including the annual SO_2 and NO_x emission allowance entitlements received at no cost from the Federal EPA. KPCo follows the inventory model for these allowances. Allowances expected to be consumed within one year are reported in Materials and Supplies. Allowances with expected consumption beyond one year are included in Deferred Charges and Other Noncurrent Assets. These allowances are consumed in the production of energy and are recorded in Fuel and Other Consumables Used for Electric Generation at an average cost. Allowances held for speculation are included in Prepayments and Other Current Assets. The purchases and sales of allowances are reported in the Operating Activities section of the Statements of Cash Flows. The net margin on sales of emission allowances is included in Electric Generation, Transmission and Distribution Revenues for nonaffiliated transactions and in Sales to AEP Affiliates Revenues for affiliated transactions because of its integral nature to the production process of energy and KPCo's revenue optimization strategy for operations. The net margin on sales of emission allowances affects the determination of deferred fuel or deferred emission allowance costs and the amortization of regulatory assets.

Property, Plant and Equipment

Electric utility property, plant and equipment are stated at original purchase cost. Additions, major replacements and betterments are added to the plant accounts. Normal and routine retirements from the plant accounts, net of salvage, are charged to accumulated depreciation under the group composite method of depreciation. The group composite method of depreciation assumes that on average, asset components are retired at the end of their useful lives and thus there is no gain or loss. The equipment in each primary electric plant account is identified as a separate group. Under the group composite method of depreciation, continuous interim routine replacements of items such as boiler tubes, pumps, motors, etc. result in the original cost, less salvage, being charged to accumulated depreciation. The depreciation rates that are established take into account the past history of interim capital replacements and the amount of salvage received. These rates and the related lives are subject to periodic review. Removal costs are charged to regulatory liabilities. The costs of labor, materials and overhead incurred to operate and maintain the plants are included in operating expenses.

Long-lived assets are required to be tested for impairment when it is determined that the carrying value of the assets may no longer be recoverable or when the assets meet the held for sale criteria under the accounting guidance for "Impairment or Disposal of Long-lived Assets."

The fair value of an asset or investment is the amount at which that asset or investment could be bought or sold in a current transaction between willing parties, as opposed to a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets or investments in active markets, fair value is estimated using various internal and external valuation methods including cash flow analysis and appraisals.

Allowance for Funds Used During Construction (AFUDC)

AFUDC represents the estimated cost of borrowed and equity funds used to finance construction projects that is capitalized and recovered through depreciation over the service life of regulated electric utility plant. KPCo records the equity component of AFUDC in Allowance for Equity Funds Used During Construction and the debt component of AFUDC as a reduction to Interest Expense.

Valuation of Nonderivative Financial Instruments

The book values of Cash and Cash Equivalents, Accounts Receivable and Accounts Payable approximate fair value because of the short-term maturity of these instruments.

Fair Value Measurements of Assets and Liabilities

The accounting guidance for "Fair Value Measurements and Disclosures" establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. When quoted market prices are not available, pricing may be completed using comparable securities, dealer values, operating data and general market conditions to determine fair value. Valuation models utilize various inputs such as commodity, interest rate and, to a lesser degree, volatility or credit that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability.

For commercial activities, exchange traded derivatives, namely futures contracts, are generally fair valued based on unadjusted quoted prices in active markets and are classified as Level 1. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, as well as exchange traded contracts where there is insufficient market liquidity to warrant inclusion in Level 1. Management verifies price curves using these broker quotes and classifies these fair values within Level 2 when substantially all of the fair value can be corroborated. Management typically obtains multiple broker quotes, which are non-binding in nature, but are based on recent trades in the marketplace. When multiple broker quotes are obtained, the quoted bid and ask prices are averaged. In certain circumstances, a broker quote may be discarded if it is a clear outlier. Management uses a historical correlation analysis between the broker quoted location and the illiquid locations and if the points are highly correlated, these locations are included within Level 2 as well. Certain OTC and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. Long-dated and illiquid complex or structured transactions and FTRs can introduce the need for internally developed modeling inputs based upon extrapolations and assumptions of observable market data to estimate fair value. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized as Level 3.

AEP utilizes its trustee's external pricing service to estimate the fair value of the underlying investments held in the benefit plan trusts. AEP's investment managers review and validate the prices utilized by the trustee to determine fair value. AEP's investment managers perform their own valuation testing to verify the fair values of the securities. AEP receives audit reports of the trustee's operating controls and valuation processes. The trustee uses multiple pricing vendors for the assets held in the plans.

Assets in the benefits trust are classified using the following methods. Equities are classified as Level 1 holdings if they are actively traded on exchanges. Items classified as Level 1 are investments in money market funds, fixed income and equity mutual funds and domestic equity securities. They are valued based on observable inputs primarily unadjusted quoted prices in active markets for identical assets. Fixed income securities do not trade on an exchange and do not have an official closing price. Pricing vendors calculate bond valuations using financial models and matrices. Fixed income securities are typically classified as Level 2 holdings because their valuation inputs are based on observable market data. Observable inputs used for valuing fixed income securities are benchmark yields, reported trades, broker/dealer quotes, issuer spreads, two-sided markets, benchmark securities, bids, offers, reference data and economic events. Other securities with model-derived valuation inputs that are observable are also classified as Level 2 investments. Investments with unobservable valuation inputs are classified as Level 3 investments. Benefit plan assets included in Level 3 are real estate and private equity investments that are valued using methods requiring judgment including appraisals.

Items classified as Level 2 are primarily investments in individual fixed income securities. These fixed income securities are valued using models with input data as follows:

	Type of Fixed Income Security		
Type of Input	**United States Government**	**Corporate Debt**	**State and Local Government**
Benchmark Yields	X	X	X
Broker Quotes	X	X	X
Discount Margins	X	X	
Treasury Market Update	X		
Base Spread	X	X	X
Corporate Actions		X	
Ratings Agency Updates		X	X
Prepayment Schedule and History			X
Yield Adjustments	X		

Deferred Fuel Costs

The cost of fuel and related emission allowances and emission control chemicals/consumables is charged to Fuel and Other Consumables Used for Electric Generation expense when the fuel is burned or the allowance or consumable is utilized. Fuel cost over-recoveries (the excess of fuel revenues billed to customers over applicable fuel costs incurred) are deferred as current regulatory liabilities and under-recoveries (the excess of applicable fuel costs incurred over fuel revenues billed to customers) are deferred as current regulatory assets. These deferrals are amortized when refunded or when billed to customers in later months with the KPSC's review and approval. The amount of an over-recovery or under-recovery can also be affected by actions of the KPSC. On a routine basis, the KPSC reviews and/or audits KPCo's fuel procurement policies and practices, the fuel cost calculations and FAC deferrals. When a fuel cost disallowance becomes probable, KPCo adjusts its FAC deferrals and records a provision for estimated refunds to recognize these probable outcomes. Changes in fuel costs, including purchased power are reflected in rates in a timely manner through the FAC. A portion of profits from off-system sales are shared with customers through the FAC.

Revenue Recognition

Regulatory Accounting

KPCo's financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated. Regulatory assets (deferred expenses) and regulatory liabilities (deferred revenue reductions or refunds) are recorded to reflect the economic effects of regulation in the same accounting period by matching expenses with their recovery through regulated revenues and by matching income with its passage to customers in cost-based regulated rates.

When regulatory assets are probable of recovery through regulated rates, KPCo records them as assets on its balance sheet. KPCo tests for probability of recovery at each balance sheet date or whenever new events occur. Examples of new events include the issuance of a regulatory commission order or passage of new legislation. If it is determined that recovery of a regulatory asset is no longer probable, KPCo writes off that regulatory asset as a charge against income.

Traditional Electricity Supply and Delivery Activities

KPCo recognizes revenues from retail and wholesale electricity sales and electricity transmission and distribution delivery services. KPCo recognizes the revenues in the financial statements upon delivery of the energy to the customer and includes unbilled as well as billed amounts.

Most of the power produced at the generation plants of the AEP East companies is sold to PJM, the RTO operating in the east service territory. The AEP East companies purchase power from PJM to supply power to their customers. Generally, these power sales and purchases are reported on a net basis in Revenues in the Statements of Income. However, purchases of power in excess of sales to PJM, on an hourly net basis, used to serve retail load are recorded gross as Purchased Electricity for Resale on the Statements of Income. Other RTOs do not function in the same manner as PJM. They function as balancing organizations and not as exchanges.

Physical energy purchases arising from non-derivative contracts are accounted for on a gross basis in Purchased Electricity for Resale on the Statements of Income. Energy purchases arising from non-trading derivative contracts are recorded based on the transaction's economic substance. Purchases under non-trading derivatives used to serve accrual based obligations are recorded in Purchased Electricity for Resale on the Statements of Income. All other non-trading derivative purchases are recorded net in revenues.

In general, KPCo records expenses upon receipt of purchased electricity and when expenses are incurred, with the exception of certain power purchase contracts that are derivatives and accounted for using MTM accounting. KPCo, which operates solely in a jurisdiction where the generation/supply business is subject to cost-based regulation, defers the unrealized MTM amounts as regulatory assets (for losses) and regulatory liabilities (for gains).

Energy Marketing and Risk Management Activities

AEPSC, on behalf of the AEP East companies, engages in wholesale electricity, natural gas, coal and emission allowances marketing and risk management activities focused on wholesale markets where the AEP System owns assets and adjacent markets. These activities include the purchase and sale of energy under forward contracts at fixed and variable prices and the buying and selling of financial energy contracts which include exchange traded futures and options, as well as over-the-counter options and swaps. Certain energy marketing and risk management transactions are with RTOs.

KPCo recognizes revenues and expenses from wholesale marketing and risk management transactions that are not derivatives upon delivery of the commodity. KPCo uses MTM accounting for wholesale marketing and risk management transactions that are derivatives unless the derivative is designated in a qualifying cash flow hedge relationship or a normal purchase or sale. The realized gains and losses on wholesale marketing and risk management transactions are included in Revenues in the Statements of Income on a net basis. The unrealized MTM amounts are deferred as regulatory assets (for losses) and regulatory liabilities (for gains). Unrealized MTM gains and losses are included on the balance sheets as Risk Management Assets or Liabilities as appropriate.

Certain qualifying wholesale marketing and risk management derivative transactions are designated as hedges of variability in future cash flows as a result of forecasted transactions (cash flow hedge). KPCo initially records the effective portion of the cash flow hedge's gain or loss as a component of AOCI. When the forecasted transaction is realized and affects net income, KPCo subsequently reclassifies the gain or loss on the hedge from Accumulated Other Comprehensive Income into revenues or expenses within the same financial statement line item as the forecasted transaction on its Statements of Income. KPCo defers the ineffective portion as regulatory assets (for losses) and regulatory liabilities (for gains). See "Accounting for Cash Flow Hedging Strategies" section of Note 7.

Maintenance

Maintenance costs are expensed as incurred. If it becomes probable that KPCo will recover specifically-incurred costs through future rates, a regulatory asset is established to match the expensing of those maintenance costs with their recovery in cost-based regulated revenues.

Income Taxes and Investment Tax Credits

KPCo uses the liability method of accounting for income taxes. Under the liability method, deferred income taxes are provided for all temporary differences between the book and tax basis of assets and liabilities which will result in a future tax consequence.

When the flow-through method of accounting for temporary differences is reflected in regulated revenues (that is, when deferred taxes are not included in the cost of service for determining regulated rates for electricity), deferred income taxes are recorded and related regulatory assets and liabilities are established to match the regulated revenues and tax expense.

Investment tax credits are 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 amortized over the life of the plant investment.

KPCo accounts for uncertain tax positions in accordance with the accounting guidance for "Income Taxes." KPCo classifies interest expense or income related to uncertain tax positions as interest expense or income as appropriate and classifies penalties as Other Operation.

Excise Taxes

As an agent for some state and local governments, KPCo collects from customers certain excise taxes levied by those state or local governments on customers. KPCo does not recognize these taxes as revenue or expense.

Debt

Gains and losses from the reacquisition of debt used to finance regulated electric utility plants are deferred and amortized over the remaining term of the reacquired debt in accordance with their rate-making treatment unless the debt is refinanced. If the reacquired debt is refinanced, the reacquisition costs are generally deferred and amortized over the term of the replacement debt consistent with its recovery in rates.

Debt discount or premium and debt issuance expenses are deferred and amortized generally utilizing the straight-line method over the term of the related debt. The straight-line method approximates the effective interest method and is consistent with the treatment in rates for regulated operations. The net amortization expense is included in Interest Expense.

Investments Held in Trust for Future Liabilities

AEP has several trust funds with significant investments intended to provide for future payments of pension and OPEB benefits. All of the trust funds' investments are diversified and managed in compliance with all laws and regulations. The investment strategy for trust funds is to use a diversified portfolio of investments to achieve an acceptable rate of return while managing the interest rate sensitivity of the assets relative to the associated liabilities. To minimize investment risk, the trust funds are broadly diversified among classes of assets, investment strategies and investment managers. Management regularly reviews the actual asset allocation and periodically rebalance the investments to targeted allocation when appropriate. Investment policies and guidelines allow investment managers in approved strategies to use financial derivatives to obtain or manage market exposures and to hedge assets and liabilities. The investments are reported at fair value under the "Fair Value Measurements and Disclosures" accounting guidance.

Benefit Plans

All benefit plan assets are invested in accordance with each plan's investment policy. The investment policy outlines the investment objectives, strategies and target asset allocations by plan.

The investment philosophies for AEP's benefit plans support the allocation of assets to minimize risks and optimizing net returns. Strategies used include:

- Maintaining a long-term investment horizon.
- Diversifying assets to help control volatility of returns at acceptable level.
- Managing fees, transaction costs and tax liabilities to maximize investment earnings.
- Using active management of investments where appropriate risk/return opportunities exist.
- Keeping portfolio structure style-neutral to limit volatility compared to applicable benchmarks.
- Using alternative asset classes such as real estate and private equity to maximize return and provide additional portfolio diversification.

The target asset allocation and allocation ranges are as follows:

Pension Plan Assets	Minimum	Target	Maximum
Domestic Equity	30.0 %	35.0 %	40.0 %
International and Global Equity	10.0 %	15.0 %	20.0 %
Fixed Income	35.0 %	39.0 %	45.0 %
Real Estate	4.0 %	5.0 %	6.0 %
Other Investments	1.0 %	5.0 %	7.0 %
Cash	0.5 %	1.0 %	3.0 %

OPEB Plans Assets	Minimum	Target	Maximum
Equity	61.0 %	66.0 %	71.0 %
Fixed Income	29.0 %	32.0 %	37.0 %
Cash	1.0 %	2.0 %	4.0 %

The investment policy for each benefit plan contains various investment limitations. The investment policies establish concentration limits for securities. Investment policies prohibit the benefit trust funds from purchasing securities issued by AEP (with the exception of proportionate and immaterial holdings of AEP securities in passive index strategies). However, the investment policies do not preclude the benefit trust funds from receiving contributions in the form of AEP securities, provided that the AEP securities acquired by each plan may not exceed the limitations imposed by law. Each investment manager's portfolio is compared to a diversified benchmark index.

For equity investments, the limits are as follows:

- No security in excess of 5% of all equities.
- Cash equivalents must be less than 10% of an investment manager's equity portfolio.
- Individual stock must be less than 10% of each manager's equity portfolio.
- No investment in excess of 5% of an outstanding class of any company.
- No securities may be bought or sold on margin or other use of leverage.

For fixed income investments, the concentration limits must not exceed:

- 3% in one issuer
- 20% in non-US dollar denominated
- 5% private placements
- 5% convertible securities
- 60% for bonds rated AA+ or lower
- 50% for bonds rated A+ or lower
- 10% for bonds rated BBB- or lower

For obligations of non-government issuers the following limitations apply:

- AAA rated debt: a single issuer should account for no more than 5% of the portfolio.
- AA+, AA, AA- rated debt: a single issuer should account for no more than 3% of the portfolio.
- Debt rated A+ or lower: a single issuer should account for no more than 2% of the portfolio.
- No more than 10% of the portfolio may be invested in high yield and emerging market debt combined at any time.

A portion of the pension assets is invested in real estate funds to provide diversification, add return, and hedge against inflation. Real estate properties are illiquid, difficult to value, and not actively traded. The pension plan uses external real estate investment managers to invest in commingled funds that hold real estate properties. To mitigate investment risk in the real estate portfolio, commingled real estate funds are used to ensure that holdings are diversified by region, property type, and risk classification. Real estate holdings include core, value-added, and development risk classifications and some investments in Real Estate Investment Trusts (REITs), which are publicly traded real estate securities classified as Level 1.

A portion of the pension assets is invested in private equity. Private equity investments add return and provide diversification and typically require a long-term time horizon to evaluate investment performance. Private equity is classified as an alternative investment because it is illiquid, difficult to value, and not actively traded. The pension plan uses limited partnerships and commingled funds to invest across the private equity investment spectrum. The private equity holdings are with six general partners who help monitor the investments and provide investment selection expertise. The holdings are currently comprised of venture capital, buyout, and hybrid debt and equity investment instruments. Commingled private equity funds are used to enhance the holdings' diversity.

AEP participates in a securities lending program with BNY Mellon to provide incremental income on idle assets and to provide income to offset custody fees and other administrative expenses. AEP lends securities to borrowers approved by BNY Mellon in exchange for cash collateral. All loans are collateralized by at least 102% of the loaned asset's market value and the cash collateral is invested. The difference between the rebate owed to the borrower and the cash collateral rate of return determines the earnings on the loaned security. The securities lending program's objective is providing modest incremental income with a limited increase in risk.

Trust owned life insurance (TOLI) underwritten by The Prudential Insurance Company is held in the OPEB plan trusts. The strategy for holding life insurance contracts in the taxable Voluntary Employees' Beneficiary Association (VEBA) trust is to minimize taxes paid on the asset growth in the trust. Earnings on plan assets are tax-deferred within the TOLI contract and can be tax-free if held until claims are paid. Life insurance proceeds remain in the trust and are used to fund future retiree medical benefit liabilities. With consideration to other investments held in the trust, the cash value of the TOLI contracts is invested in two diversified funds. A portion is invested in a commingled fund with underlying investments in stocks that are actively traded on major international equity exchanges. The other portion of the TOLI cash value is invested in a diversified, commingled fixed income fund with underlying investments in government bonds, corporate bonds and asset-backed securities.

Cash and cash equivalents are held in each trust to provide liquidity and meet short-term cash needs. Cash equivalent funds are used to provide diversification and preserve principal. The underlying holdings in the cash funds are investment grade money market instruments including commercial paper, certificates of deposit, treasury bills and other types of investment grade short-term debt securities. The cash funds are valued each business day and provide daily liquidity.

Comprehensive Income (Loss)

Comprehensive income (loss) is defined as the change in equity (net assets) of a business enterprise during a period from transactions and other events and circumstances from nonowner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners. Comprehensive income (loss) has two components: net income (loss) and other comprehensive income (loss).

Components of Accumulated Other Comprehensive Income (Loss) (AOCI)

AOCI is included on the balance sheets in the common shareholder's equity section. KPCo's components of AOCI as of December 31, 2010 and 2009 are shown in the following table:

Components	December 31, 2010	December 31, 2009
	(in thousands)	
Cash Flow Hedges, Net of Tax	$ (451)	$ (601)

Earnings Per Share (EPS)

KPCo is a wholly-owned subsidiary of AEP. Therefore, KPCo is not required to report EPS.

Subsequent Events

Management reviewed subsequent events through February 25, 2011, the date that KPCo's 2010 annual report was issued.

Adjustments to Sale of Receivables Disclosure

In the "Sale of Receivables – AEP Credit" section of Note 11, the disclosure was expanded for KPCo to reflect certain prior period amounts related to the sale of receivables that were not previously disclosed. These omissions were not material to the disclosure and had no impact on KPCo's previously reported net income, changes in shareholder's equity, financial position or cash flows.

Adjustments to Benefit Plans Footnote

In Note 5 – Benefit Plans, the disclosure was expanded to reflect disclosure requirements based upon KPCo's participation in the AEP System. These omissions were not material to the financial statements and had no impact on KPCo's previously reported net income, changes in shareholder's equity, financial position or cash flows.

2. RATE MATTERS

KPCo is involved in rate and regulatory proceedings at the FERC and the KPSC. Rate matters can have a material impact on net income, cash flows and possibly financial condition. KPCo's recent significant rate orders and pending rate filings are addressed in this note.

Kentucky Base Rate Filing

In December 2009, KPCo filed a base rate case with the KPSC to increase base revenues by $124 million annually based on an 11.75% return on common equity. The base rate case also requested recovery of deferred storm restoration expenses over a three-year period. In June 2010, the KPSC approved a settlement agreement to increase base revenues by $64 million annually based on a 10.5% return on common equity. The settlement agreement included recovery of $23 million of deferred storm restoration expenses over five years. New rates became effective with the first billing cycle of July 2010.

Validity of Nonstatutory Surcharges

The Franklin County Circuit Court concluded the KPSC did not have the authority to order a surcharge for a gas company subsidiary of Duke Energy absent a full cost of service rate proceeding due to the lack of statutory authority. Although this order is not directly applicable, KPCo has existing surcharges which are not specifically authorized by statute. These include KPCo's fuel clause surcharge, the annual Rockport Plant capacity surcharge, the merger surcredit and the off-system sales credit rider. The KPSC filed for a discretionary review of the related Duke Energy case with the Kentucky Supreme Court. In October 2010, the Kentucky Supreme Court ruled that as long as rates established by a utility are fair, just and reasonable, the KPSC has broad ratemaking power to allow recovery of costs outside of a general rate case, even without a statute specifically authorizing recovery of such costs.

FERC Rate Matters

Seams Elimination Cost Allocation (SECA) Revenue Subject to Refund

In 2004, AEP eliminated transaction-based through-and-out transmission service (T&O) charges in accordance with FERC orders and collected, at the FERC's direction, load-based charges, referred to as RTO SECA, to partially mitigate the loss of T&O revenues on a temporary basis through March 2006. Intervenors objected to the temporary SECA rates. The FERC set SECA rate issues for hearing and ordered that the SECA rate revenues be collected, subject to refund. The AEP East companies recognized gross SECA revenues of $220 million from 2004 through 2006 when the SECA rates terminated. KPCo's portion of recognized gross SECA revenues was $17 million.

In 2006, a FERC Administrative Law Judge (ALJ) issued an initial decision finding that the SECA rates charged were unfair, unjust and discriminatory and that new compliance filings and refunds should be made. The ALJ also found that any unpaid SECA rates must be paid in the recommended reduced amount.

AEP filed briefs jointly with other affected companies asking the FERC to reverse the decision. In May 2010, the FERC issued an order that generally supports AEP's position and requires a compliance filing to be filed with the FERC by August 2010. In June 2010, AEP and other affected companies filed a joint request for rehearing with the FERC.

The AEP East companies provided reserves for net refunds for SECA settlements totaling $44 million applicable to the $220 million of SECA revenues collected. KPCo provided a reserve of $3.3 million.

Settlements approved by the FERC consumed $10 million of the reserve for refunds applicable to $112 million of SECA revenue. In December 2010, the FERC issued an order approving a settlement agreement resulting in the collection of $2 million of previously deemed uncollectible SECA revenue. Therefore, the AEP East companies reduced their reserves for net refunds for SECA settlements by $2 million. The balance in the reserve for future settlements as of December 31, 2010 was $32 million. KPCo's portion of the reserve balance at December 31, 2010 was $2.4 million.

In August 2010, the affected companies, including the AEP East companies, filed a compliance filing with the FERC. If the compliance filing is accepted, the AEP East companies would have to pay refunds of approximately $20 million including estimated interest of $5 million. The AEP East companies could also potentially receive payments up to approximately $10 million including estimated interest of $3 million. KPCo's portion of the potential refund payments and potential payments to be received are $1.5 million and $800 thousand, respectively. A decision is pending from the FERC.

Based on the AEP East companies' analysis of the May 2010 order and the compliance filing, management believes that the reserve is adequate to pay the refunds, including interest, that will be required should the May 2010 order or the compliance filing be made final. Management cannot predict the ultimate outcome of this proceeding at the FERC which could impact future net income and cash flows.

Modification of the Transmission Agreement (TA)

The AEP East companies are parties to the TA that provides for a sharing of the cost of transmission lines operated at 138-kV and above and transmission stations containing extra-high voltage facilities. In June 2009, AEPSC, on behalf of the parties to the TA, filed with the FERC a request to modify the TA. Under the proposed amendments, KGPCo and WPCo will be added as parties to the TA. In addition, the amendments would provide for the allocation of PJM transmission costs generally on the basis of the TA parties' 12-month coincident peak and reimburse transmission revenues based on individual cost of service instead of the MLR method used in the present TA. In October 2010, the FERC approved a settlement agreement for the new TA effective November 1, 2010. The impacts of the settlement agreement will be phased-in for retail rate making purposes in certain jurisdictions over periods of up to four years.

PJM Transmission Formula Rate Filing

AEP filed an application with the FERC in July 2008 to increase its open access transmission tariff (OATT) rates for wholesale transmission service within PJM. The filing sought to implement a formula rate allowing annual adjustments reflecting future changes in the AEP East companies' cost of service. The FERC issued an order conditionally accepting AEP's proposed formula rate and delayed the requested October 2008 effective date for five months. AEP began settlement discussions with the intervenors and the FERC staff which resulted in a settlement that was filed with the FERC in April 2010.

In October 2010, a settlement agreement was approved by the FERC which resulted in a $51 million annual increase beginning in April 2009 for service as of March 2009, of which approximately $7 million is being collected from nonaffiliated customers within PJM. Prior to November 2010, the remaining $44 million was billed to the AEP East companies and was generally offset by compensation from PJM for use of the AEP East companies' transmission facilities so that net income was not directly affected. Beginning in November 2010, AEP East companies, KGPCo and WPCo, which are parties to the modified TA, allocate revenue and expenses on different methodologies and will affect net income. See "Modification of the Transmission Agreement" above.

The settlement also results in an additional $30 million increase for the first annual update of the formula rate, beginning in August 2009 for service as of July 2009. Approximately $4 million of the increase will be collected from nonaffiliated customers within PJM with the remaining $26 million being billed to the AEP East companies.

Under the formula, an annual update will be filed to be effective July 2010 and each year thereafter. Also, beginning with the July 2010 update, the rates each year will include an adjustment to true-up the prior year's collections to the actual costs for the prior year. In May 2010, the second annual update was filed with the FERC to decrease the revenue requirement by $58 million for service as of July 2010. Approximately $8 million of the decrease will be refunded to nonaffiliated customers within PJM.

PJM/MISO Market Flow Calculation Settlement Adjustments

During 2009, an analysis conducted by MISO and PJM discovered several instances of unaccounted for power flows on numerous coordinated flowgates. These flows affected the settlement data for congestion revenues and expenses and dated back to the start of the MISO market in 2005. In January 2011, PJM and MISO reached a settlement agreement where the parties agreed to net various issues to zero. This settlement was filed with the FERC in January 2011. PJM and MISO are currently awaiting final approval from the FERC.

Transmission Agreement (TA)

Certain transmission facilities placed in service in 1998 were inadvertently excluded from the AEP East companies' TA calculation prior to January 2009. The excluded equipment was KPCo's Inez Station which had been determined as eligible equipment for inclusion in the TA in 1995 by the AEP TA transmission committee. The amount involved was $7 million annually. In June 2010, the KPSC approved a settlement agreement in KPCo's base rate filing which set new base rates effective July 2010 and excluded consideration of this issue.

3. EFFECTS OF REGULATION

Regulatory assets and liabilities are comprised of the following items:

Regulatory Assets:	December 31, 2010	2009	Remaining Recovery Period
	(in thousands)		
Noncurrent Regulatory Assets			
Regulatory assets not yet being recovered pending future proceedings to determine the recovery method and timing:			
Regulatory Assets Currently Not Earning a Return			
Storm Related Costs	$ - (a)	$ 24,355	
Total Regulatory Assets Not Yet Being Recovered	-	24,355	
Regulatory assets being recovered:			
Regulatory Assets Currently Earning a Return			
RTO Formation/Integration Costs	1,373	1,538	9 years
Unamortized Loss on Reacquired Debt	737	771	22 years
Regulatory Assets Currently Not Earning a Return			
Income Taxes, Net	123,789	114,131	23 years
Pension and OPEB Funded Status	58,853	56,848	13 years
Storm Related Costs	21,143 (a)	-	5 years
Postemployment Benefits	6,456	7,077	4 years
Other Regulatory Assets Being Recovered	1,242	1,354	various
Total Regulatory Assets Being Recovered	213,593	181,719	
Total Noncurrent Regulatory Assets	$ 213,593	$ 206,074	

Regulatory Liabilities:	December 31, 2010	2009	Remaining Refund Period
	(in thousands)		
Current Regulatory Liability			
Over-recovered Fuel Costs - does not pay a return	$ 864	$ 1,787	1 year
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities being paid:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	27,975	24,979	(b)
Regulatory Liabilities Currently Not Paying a Return			
Unrealized Gain on Forward Commitments	5,844	8,977	5 years
Deferred Investment Tax Credits	993	1,697	10 years
Other Regulatory Liabilities Being Paid	179	25	various
Total Regulatory Liabilities Being Paid	34,991	35,678	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 34,991	$ 35,678	

(a) Recovery of regulatory asset was granted during 2010.
(b) Relieved as removal costs are incurred.

4. COMMITMENTS, GUARANTEES AND CONTINGENCIES

KPCo is subject to certain claims and legal actions arising in its ordinary course of business. In addition, KPCo's business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation cannot be predicted. For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material adverse effect on the financial statements.

COMMITMENTS

KPCo has substantial construction commitments to support its operations and environmental investments. In managing the overall construction program and in the normal course of business, KPCo contractually commits to third-party construction vendors for certain material purchases and other construction services. Management forecasts approximately $86 million of construction expenditures excluding AFUDC for 2011. KPCo also purchases fuel, materials, supplies, services and property, plant and equipment under contract as part of its normal course of business. Certain supply contracts contain penalty provisions for early termination.

The following table summarizes KPCo's actual contractual commitments at December 31, 2010:

Contractual Commitments	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 181.9	$ 188.7	$ -	$ -	$ 370.6
Energy and Capacity Purchase Contracts (b)	0.9	0.4	0.1	-	1.4
Total	$ 182.8	$ 189.1	$ 0.1	$ -	$ 372.0

(a) Represents contractual commitments to purchase coal and other consumables as fuel for electric generation along with related transportation of the fuel.

(b) Represents contractual commitments for energy and capacity purchase contracts.

GUARANTEES

Liabilities for guarantees are recorded in accordance with the accounting guidance for "Guarantees." There is no collateral held in relation to any guarantees. In the event any guarantee is drawn, there is no recourse to third parties.

Indemnifications and Other Guarantees

Contracts

KPCo enters into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. There are no material liabilities recorded for any indemnifications.

KPCo, along with the other AEP East companies, PSO and SWEPCo, are jointly and severally liable for activity conducted by AEPSC on behalf of the AEP East companies, PSO and SWEPCo related to purchase power and sale activity conducted pursuant to the SIA.

Lease Obligations

KPCo leases certain equipment under master lease agreements. See "Master Lease Agreements" section of Note 10 for disclosure of lease residual value guarantees.

CONTINGENCIES

Insurance and Potential Losses

KPCo maintains insurance coverage normal and customary for an electric utility, subject to various deductibles. The insurance includes coverage for all risks of physical loss or damage to assets, subject to insurance policy conditions and exclusions. Covered property generally includes power plants, substations, facilities and inventories. Excluded property generally includes transmission and distribution lines, poles and towers. The insurance programs also generally provide coverage against loss arising from certain claims made by third parties and are in excess of KPCo's retentions. Coverage is generally provided by a combination of the protected cell of EIS and/or various industry mutual and/or commercial insurance carriers.

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities. Future losses or liabilities, if they occur, which are not completely insured, unless recovered from customers, could have a material adverse effect on net income, cash flows and financial condition.

Carbon Dioxide Public Nuisance Claims

In 2004, eight states and the City of New York filed an action in Federal District Court for the Southern District of New York against AEP, AEPSC, Cinergy Corp, Xcel Energy, Southern Company and Tennessee Valley Authority. The Natural Resources Defense Council, on behalf of three special interest groups, filed a similar complaint against the same defendants. The actions allege that CO_2 emissions from the defendants' power plants constitute a public nuisance under federal common law due to impacts of global warming and sought injunctive relief in the form of specific emission reduction commitments from the defendants. The trial court dismissed the lawsuits.

In September 2009, the Second Circuit Court of Appeals issued a ruling on appeal remanding the cases to the Federal District Court for the Southern District of New York. The Second Circuit held that the issues of climate change and global warming do not raise political questions and that Congress' refusal to regulate CO_2 emissions does not mean that plaintiffs must wait for an initial policy determination by Congress or the President's administration to secure the relief sought in their complaints. The court stated that Congress could enact comprehensive legislation to regulate CO_2 emissions or that the Federal EPA could regulate CO_2 emissions under existing Clean Air Act authorities and that either of these actions could override any decision made by the district court under federal common law. The Second Circuit did not rule on whether the plaintiffs could proceed with their state common law nuisance claims. In December 2010, the defendants' petition for review by the U.S. Supreme Court was granted. Briefing is underway and the case will be heard in April 2011. Management believes the actions are without merit and intends to continue to defend against the claims.

In October 2009, the Fifth Circuit Court of Appeals reversed a decision by the Federal District Court for the District of Mississippi dismissing state common law nuisance claims in a putative class action by Mississippi residents asserting that CO_2 emissions exacerbated the effects of Hurricane Katrina. The Fifth Circuit held that there was no exclusive commitment of the common law issues raised in plaintiffs' complaint to a coordinate branch of government and that no initial policy determination was required to adjudicate these claims. The court granted petitions for rehearing. An additional recusal left the Fifth Circuit without a quorum to reconsider the decision and the appeal was dismissed, leaving the district court's decision in place. Plaintiffs filed a petition with the U.S. Supreme Court asking the court to remand the case to the Fifth Circuit and reinstate the panel decision. The petition was denied in January 2011.

Management is unable to determine a range of potential losses that are reasonably possible of occurring.

Alaskan Villages' Claims

In 2008, the Native Village of Kivalina and the City of Kivalina, Alaska filed a lawsuit in Federal Court in the Northern District of California against AEP, AEPSC and 22 other unrelated defendants including oil and gas companies, a coal company and other electric generating companies. The complaint alleges that the defendants' emissions of CO_2 contribute to global warming and constitute a public and private nuisance and that the defendants are acting together. The complaint further alleges that some of the defendants, including AEP, conspired to create a false scientific debate about global warming in order to deceive the public and perpetuate the alleged nuisance. The plaintiffs also allege that the effects of global warming will require the relocation of the village at an alleged cost of $95 million to $400 million. In October 2009, the judge dismissed plaintiffs' federal common law claim for nuisance, finding the claim barred by the political question doctrine and by plaintiffs' lack of standing to bring the claim. The judge also dismissed plaintiffs' state law claims without prejudice to refiling in state court. The plaintiffs appealed the decision. Briefing is complete and no date has been set for oral argument. The defendants requested that the court defer setting this case for oral argument until after the Supreme Court issues its decision in the CO_2 public nuisance case discussed above. Management believes the action is without merit and intends to defend against the claims. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

The Comprehensive Environmental Response Compensation and Liability Act (Superfund) and State Remediation

By-products from the generation of electricity include materials such as ash, slag and sludge. Coal combustion by-products, which constitute the overwhelming percentage of these materials, are typically treated and deposited in captive disposal facilities or are beneficially utilized. In addition, the generating plants and transmission and distribution facilities have used asbestos, polychlorinated biphenyls and other hazardous and nonhazardous materials. KPCo currently incurs costs to dispose of these substances safely.

Superfund addresses clean-up of hazardous substances that have been released to the environment. The Federal EPA administers the clean-up programs. Several states have enacted similar laws. At December 31, 2010, there is one site for which KPCo has received an information request which could lead a Potentially Responsible Party designation. In the instance where KPCo has been named a defendant, disposal or recycling activities were in accordance with the then-applicable laws and regulations. Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories. Liability has been resolved for a number of sites with no significant effect on net income.

Management evaluates the potential liability for each site separately, but several general statements can be made about potential future liability. Allegations that materials were disposed at a particular site are often unsubstantiated and the quantity of materials deposited at a site can be small and often nonhazardous. Although Superfund liability has been interpreted by the courts as joint and several, typically many parties are named for each site and several of the parties are financially sound enterprises. At present, management's estimates do not anticipate material cleanup costs for identified sites.

Defective Environmental Equipment

As part of the AEP System's continuing environmental investment program, management chose to retrofit wet flue gas desulfurization systems on one unit of the Big Sandy Plant utilizing the jet bubbling reactor (JBR) technology. Contracts for the project have been suspended. The retrofits on three units owned by KPCo's affiliates are operational. Due to unexpected operating results, management completed an extensive review of the design and manufacture of the JBR internal components. The review concluded that there were fundamental design deficiencies and that inferior and/or inappropriate materials were selected for the internal fiberglass components. Management initiated discussions with Black & Veatch, the original equipment manufacturer, to develop a repair or replacement corrective action plan. In 2010, management settled with Black & Veatch and resolved the issues involving the internal components and JBR vessel corrosion. These settlements resulted in an immaterial increase in the capitalized costs of the projects for modification of the scope of the contracts.

5. BENEFIT PLANS

For a discussion of investment strategy, investment limitations, target asset allocations and the classification of investments within the fair value hierarchy, see "Investments Held in Trust for Future Liabilities" and "Fair Value Measurements of Assets and Liabilities" sections of Note 1.

KPCo participates in an AEP sponsored qualified pension plan which covers substantially all of KPCo's employees. KPCo also participates in OPEB plans sponsored by AEP to provide medical and life insurance benefits for retired employees.

KPCo recognizes its funded status associated with defined benefit pension and OPEB plans in its balance sheets. Disclosures about the plans are required by the "Compensation – Retirement Benefits" accounting guidance. KPCo recognizes an asset for a plan's overfunded status or a liability for a plan's underfunded status and recognizes, as a component of other comprehensive income, the changes in the funded status of the plan that arise during the year that are not recognized as a component of net periodic benefit cost. KPCo records a regulatory asset instead of other comprehensive income for qualifying benefit costs of regulated operations that for ratemaking purposes are deferred for future recovery. The cumulative funded status adjustment is equal to the remaining unrecognized deferrals for unamortized actuarial losses or gains, prior service costs and transition obligations, such that remaining deferred costs result in a regulatory asset and deferred gains result in a regulatory liability.

Actuarial Assumptions for Benefit Obligations

The weighted-average assumptions as of December 31 of each year used in the measurement of KPCo's benefit obligations are shown in the following table:

	Pension Plans		Other Postretirement Benefit Plans	
Assumptions	**2010**	**2009**	**2010**	**2009**
Discount Rate	5.05 %	5.60 %	5.25 %	5.85 %
Rate of Compensation Increase	4.55 % (a)	4.20 % (a)	N/A	N/A

(a) Rates are for base pay only. In addition, an amount is added to reflect target incentive compensation for exempt employees and overtime and incentive pay for nonexempt employees.

N/A Not Applicable

A duration-based method is used to determine the discount rate for the plans. A hypothetical portfolio of high quality corporate bonds similar to those included in the Moody's Aa bond index is constructed with a duration matching the benefit plan liability. The composite yield on the hypothetical bond portfolio is used as the discount rate for the plan.

For 2010, the rate of compensation increase assumed varies with the age of the employee, ranging from 3.5% per year to 11.5% per year, with an average increase of 4.55%.

Actuarial Assumptions for Net Periodic Benefit Costs

The weighted-average assumptions as of January 1 of each year used in the measurement of KPCo's benefit costs are shown in the following table:

	Pension Plans			Other Postretirement Benefit Plans		
	2010	**2009**	**2008**	**2010**	**2009**	**2008**
Discount Rate	5.60 %	6.00 %	6.00 %	5.85 %	6.10 %	6.20 %
Expected Return on Plan Assets	8.00 %	8.00 %	8.00 %	8.00 %	7.75 %	8.00 %
Rate of Compensation Increase	4.20 %	5.50 %	5.50 %	N/A	N/A	N/A

N/A Not Applicable

The expected return on plan assets for 2010 was determined by evaluating historical returns, the current investment climate (yield on fixed income securities and other recent investment market indicators), rate of inflation and current prospects for economic growth.

The health care trend rate assumptions as of January 1 of each year used for OPEB plans measurement purposes are shown below:

Health Care Trend Rates	2010	2009
Initial	8.00 %	6.50 %
Ultimate	5.00 %	5.00 %
Year Ultimate Reached	2016	2012

Assumed health care cost trend rates have a significant effect on the amounts reported for the OPEB health care plans. A 1% change in assumed health care cost trend rates would have the following effects:

	1% Increase	1% Decrease
	(in thousands)	
Effect on Total Service and Interest Cost Components of Net Periodic Postretirement Health Care Benefit Cost	$ 557	$ (449)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	6,689	(5,488)

Significant Concentrations of Risk within Plan Assets

In addition to establishing the target asset allocation of plan assets, the investment policy also places restrictions on securities to limit significant concentrations within plan assets. The investment policy establishes guidelines that govern maximum market exposure, security restrictions, prohibited asset classes, prohibited types of transactions, minimum credit quality, average portfolio credit quality, portfolio duration and concentration limits. The guidelines were established to mitigate the risk of loss due to significant concentrations in any investment. The plans are monitored to control security diversification and ensure compliance with the investment policy. At December 31, 2010, the assets were invested in compliance with all investment limits. See "Investments Held in Trust for Future Liabilities" section of Note 1 for limit details.

Benefit Plan Obligations, Plan Assets and Funded Status as of December 31, 2010 and 2009

The following tables provide a reconciliation of the changes in the plans' benefit obligations, fair value of plan assets and funded status as of December 31. The benefit obligation for the defined benefit pension and OPEB plans are the projected benefit obligation and the accumulated benefit obligation, respectively.

	Pension Plans		Other Postretirement Benefit Plans	
	2010	2009	2010	2009
Change in Benefit Obligation	(in thousands)			
Benefit Obligation at January 1	$ 108,511	$ 98,421	$ 50,826	$ 48,580
Service Cost	2,549	2,572	1,060	971
Interest Cost	5,900	5,861	2,953	2,866
Actuarial Loss	7,073	7,159	4,964	213
Plan Amendment Prior Service Credit	-	-	(679)	-
Benefit Payments	(10,441)	(5,502)	(3,163)	(2,525)
Participant Contributions	-	-	649	526
Medicare Subsidy	-	-	196	195
Benefit Obligation at December 31	$ 113,592	$ 108,511	$ 56,806	$ 50,826
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets at January 1	$ 81,637	$ 74,612	$ 35,553	$ 27,868
Actual Gain on Plan Assets	11,286	12,527	5,134	6,224
Company Contributions	6,184	-	2,593	3,460
Participant Contributions	-	-	649	526
Benefit Payments	(10,441)	(5,502)	(3,163)	(2,525)
Fair Value of Plan Assets at December 31	$ 88,666	$ 81,637	$ 40,766	$ 35,553
Underfunded Status at December 31	$ (24,926)	$ (26,874)	$ (16,040)	$ (15,273)

Amounts Recognized on the Balance Sheets as of December 31, 2010 and 2009

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2010	2009	2010	2009
	(in thousands)			
Employee Benefits and Pension Obligations - Accrued Long-term Benefit Liability	$ (24,926)	$ (26,874)	$ (16,040)	$ (15,273)
Underfunded Status	$ (24,926)	$ (26,874)	$ (16,040)	$ (15,273)

Amounts Included in Regulatory Assets as of December 31, 2010 and 2009

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2010	2009	2010	2009
Components	(in thousands)			
Net Actuarial Loss	$ 42,392	$ 41,003	$ 16,453	$ 14,519
Prior Service Cost (Credit)	429	579	(421)	-
Transition Obligation	-	-	-	747
Recorded as				
Regulatory Assets	$ 42,821	$ 41,582	$ 16,032	$ 15,266

Components of the change in amounts included in Regulatory Assets during the years ended December 31, 2010 and 2009 are as follows:

Components	Pension Plans 2010	Pension Plans 2009	Other Postretirement Benefit Plans 2010	Other Postretirement Benefit Plans 2009
	Years Ended December 31, (in thousands)			
Actuarial Loss (Gain) During the Year	$ 3,441	$ 2,316	$ 2,665	$ (3,856)
Prior Service Credit	-	-	(679)	-
Amortization of Actuarial Loss	(2,052)	(1,318)	(732)	(1,094)
Amortization of Prior Service Cost	(150)	(151)	-	-
Amortization of Transition Obligation	-	-	(488)	(488)
Change for the Year	$ 1,239	$ 847	$ 766	$ (5,438)

Pension and Other Postretirement Plans' Assets

The following table presents the classification of pension plan assets within the fair value hierarchy at December 31, 2010:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 31,021	$ 63	$ -	$ -	$ 31,084	35.1 %
International	9,259	-	-	-	9,259	10.4 %
Real Estate Investment Trusts	2,582	-	-	-	2,582	2.9 %
Common Collective Trust - International	-	3,738	-	-	3,738	4.2 %
Subtotal - Equities	42,862	3,801	-	-	46,663	52.6 %
Fixed Income:						
United States Government and Agency Securities	-	14,571	-	-	14,571	16.4 %
Corporate Debt	-	15,439	-	-	15,439	17.4 %
Foreign Debt	-	2,922	-	-	2,922	3.3 %
State and Local Government	-	522	-	-	522	0.6 %
Other - Asset Backed	-	1,175	-	-	1,175	1.3 %
Subtotal - Fixed Income	-	34,629	-	-	34,629	39.0 %
Real Estate	-	-	1,912	-	1,912	2.2 %
Alternative Investments	-	-	2,988	-	2,988	3.4 %
Securities Lending	-	5,845	-	-	5,845	6.6 %
Securities Lending Collateral (a)	-	-	-	(6,339)	(6,339)	(7.1)%
Cash and Cash Equivalents (b)	-	2,917	-	37	2,954	3.3 %
Other - Pending Transactions and Accrued Income (c)	-	-	-	14	14	- %
Total	$ 42,862	$ 47,192	$ 4,900	$ (6,288)	$ 88,666	100.0 %

(a) Amounts in "Other" column primarily represent an obligation to repay cash collateral received as part of the Securities Lending Program.
(b) Amounts in "Other" column primarily represent foreign currency holdings.
(c) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

The following table sets forth a reconciliation of changes in the fair value of real estate and alternative investments classified as Level 3 in the fair value hierarchy for the pension assets:

	Real Estate	Alternative Investments (in thousands)	Total Level 3
Balance as of January 1, 2010	$ 2,171	$ 2,535	$ 4,706
Actual Return on Plan Assets			
Relating to Assets Still Held as of the Reporting Date	(259)	74	(185)
Relating to Assets Sold During the Period	-	24	24
Purchases and Sales	-	355	355
Transfers into Level 3	-	-	-
Transfers out of Level 3	-	-	-
Balance as of December 31, 2010	$ 1,912	$ 2,988	$ 4,900

The following table presents the classification of OPEB plan assets within the fair value hierarchy at December 31, 2010:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 16,300	$ -	$ -	$ -	$ 16,300	40.0 %
International	6,153	-	-	-	6,153	15.1 %
Common Collective Trust - Global	-	3,203	-	-	3,203	7.9 %
Subtotal - Equities	22,453	3,203	-	-	25,656	63.0 %
Fixed Income:						
Common Collective Trust - Debt	-	1,332	-	-	1,332	3.3 %
United States Government and Agency Securities	-	2,615	-	-	2,615	6.4 %
Corporate Debt	-	3,071	-	-	3,071	7.5 %
Foreign Debt	-	692	-	-	692	1.7 %
State and Local Government	-	98	-	-	98	0.2 %
Other - Asset Backed	-	26	-	-	26	0.1 %
Subtotal - Fixed Income	-	7,834	-	-	7,834	19.2 %
Trust Owned Life Insurance:						
International Equities	-	1,369	-	-	1,369	3.3 %
United States Bonds	-	4,537	-	-	4,537	11.1 %
Cash and Cash Equivalents (a)	572	699	-	24	1,295	3.2 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	75	75	0.2 %
Total	$ 23,025	$ 17,642	$ -	$ 99	$ 40,766	100.0 %

(a) Amounts in "Other" column primarily represent foreign currency holdings.
(b) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

The following table presents the classification of pension plan assets within the fair value hierarchy at December 31, 2009:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 29,256	$ -	$ -	$ -	$ 29,256	35.8 %
International	7,674	-	-	-	7,674	9.4 %
Real Estate Investment Trusts	2,080	-	-	-	2,080	2.6 %
Common Collective Trust - International	-	3,864	-	-	3,864	4.7 %
Subtotal - Equities	39,010	3,864	-	-	42,874	52.5 %
Fixed Income:						
United States Government and Agency Securities	-	5,585	-	-	5,585	6.9 %
Corporate Debt	-	19,930	-	-	19,930	24.4 %
Foreign Debt	-	4,100	-	-	4,100	5.0 %
State and Local Government	-	826	-	-	826	1.0 %
Other - Asset Backed	-	657	-	-	657	0.8 %
Subtotal - Fixed Income	-	31,098	-	-	31,098	38.1 %
Real Estate	-	-	2,171	-	2,171	2.7 %
Alternative Investments	-	-	2,535	-	2,535	3.1 %
Securities Lending	-	4,159	-	-	4,159	5.1 %
Securities Lending Collateral (a)	-	-	-	(4,697)	(4,697)	(5.8)%
Cash and Cash Equivalents (b)	-	2,773	-	97	2,870	3.5 %
Other - Pending Transactions and Accrued Income (c)	-	-	-	627	627	0.8 %
Total	$ 39,010	$ 41,894	$ 4,706	$ (3,973)	$ 81,637	100.0 %

(a) Amounts in "Other" column primarily represent an obligation to repay cash collateral received as part of the Securities Lending Program.
(b) Amounts in "Other" column primarily represent foreign currency holdings.
(c) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

The following table sets forth a reconciliation of changes in the fair value of real estate and alternative investments classified as Level 3 in the fair value hierarchy for the pension assets:

	Real Estate	Alternative Investments	Total Level 3
		(in thousands)	
Balance as of January 1, 2009	$ 3,295	$ 2,554	$ 5,849
Actual Return on Plan Assets			
Relating to Assets Still Held as of the Reporting Date	(1,124)	(332)	(1,456)
Relating to Assets Sold During the Period	-	10	10
Purchases and Sales	-	303	303
Transfers in and/or out of Level 3	-	-	-
Balance as of December 31, 2009	$ 2,171	$ 2,535	$ 4,706

The following table presents the classification of OPEB plan assets within the fair value hierarchy at December 31, 2009:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 9,340	$ -	$ -	$ -	$ 9,340	26.2 %
International	10,190	-	-	-	10,190	28.7 %
Common Collective Trust - Global	-	2,532	-	-	2,532	7.1 %
Subtotal - Equities	19,530	2,532	-	-	22,062	62.0 %
Fixed Income:						
Common Collective Trust - Debt	-	1,032	-	-	1,032	2.9 %
United States Government and Agency Securities	-	1,139	-	-	1,139	3.2 %
Corporate Debt	-	3,847	-	-	3,847	10.8 %
Foreign Debt	-	873	-	-	873	2.4 %
State and Local Government	-	163	-	-	163	0.5 %
Other - Asset Backed	-	38	-	-	38	0.2 %
Subtotal - Fixed Income	-	7,092	-	-	7,092	20.0 %
Trust Owned Life Insurance:						
International Equities	-	2,025	-	-	2,025	5.7 %
United States Bonds	-	3,562	-	-	3,562	10.0 %
Cash and Cash Equivalents (a)	179	391	-	27	597	1.7 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	215	215	0.6 %
Total	$ 19,709	$ 15,602	$ -	$ 242	$ 35,553	100.0 %

(a) Amounts in "Other" column primarily represent foreign currency holdings.
(b) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

Determination of Pension Expense

The determination of pension expense or income is based on a market-related valuation of assets which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the market-related value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded.

Accumulated Benefit Obligation	December 31, 2010	December 31, 2009
	(in thousands)	
Qualified Pension Plan	$ 112,820	$ 107,206
Nonqualified Pension Plan	-	7
Total	$ 112,820	$ 107,213

For the underfunded pension plans that had an accumulated benefit obligation in excess of plan assets, the projected benefit obligation, accumulated benefit obligation and fair value of plan assets of these plans at December 31, 2010 and 2009 were as follows:

	Underfunded Pension Plans	
	2010	2009
	(in thousands)	
Projected Benefit Obligation	$ 113,592	$ 108,511
Accumulated Benefit Obligation	$ 112,820	$ 107,213
Fair Value of Plan Assets	88,666	81,637
Underfunded Accumulated Benefit Obligation	$ (24,154)	$ (25,576)

Estimated Future Benefit Payments and Contributions

KPCo expects contributions for the pension plan of $2.5 million and the OPEB plans of $2 million during 2011. The estimated contributions to the pension trust are at least the minimum amount required by ERISA and additional discretionary contributions may be made to maintain the funded status of the plan. The contributions to the OPEB plans are generally based on the amount of the OPEB plans' periodic benefit costs for accounting purposes as provided in agreements with state regulatory authorities, plus the additional discretionary contribution of the Medicare subsidy receipts.

The table below reflects the total benefits expected to be paid from the plan or from KPCo's assets. The payments include the participants' contributions to the plan for their share of the cost. Medicare subsidy receipts are shown in the year of the corresponding benefit payments, even though actual cash receipts are expected early in the following year. Future benefit payments are dependent on the number of employees retiring, whether the retiring employees elect to receive pension benefits as annuities or as lump sum distributions, future integration of the benefit plans with changes to Medicare and other legislation, future levels of interest rates and variances in actuarial results. The estimated payments for pension benefits and OPEB are as follows:

	Pension Plans	Other Postretirement Benefit Plans	
	Pension Payments	Benefit Payments	Medicare Subsidy Receipts
		(in thousands)	
2011	$ 6,503	$ 3,230	$ (220)
2012	6,697	3,444	(244)
2013	6,817	3,660	(276)
2014	7,121	3,875	(304)
2015	7,305	4,126	(333)
Years 2016 to 2020, in Total	41,440	24,149	(2,178)

Components of Net Periodic Benefit Cost

The following table provides the components of net periodic benefit cost for the years ended December 31, 2010, 2009 and 2008:

	Pension Plans			Other Postretirement Benefit Plans		
	Years Ended December 31,					
	2010	2009	2008	2010	2009	2008
	(in thousands)					
Service Cost	$ 2,549	$ 2,572	$ 2,508	$ 1,060	$ 971	$ 992
Interest Cost	5,900	5,861	5,712	2,953	2,866	2,966
Expected Return on Plan Assets	(7,654)	(7,684)	(7,883)	(2,841)	(2,187)	(3,031)
Amortization of Transition Obligation	-	-	-	488	488	488
Amortization of Prior Service Cost	150	151	153	-	-	-
Amortization of Net Actuarial Loss	2,052	1,318	505	732	1,094	203
Net Periodic Benefit Cost	2,997	2,218	995	2,392	3,232	1,618
Capitalized Portion	(1,064)	(825)	(454)	(849)	(1,202)	(738)
Net Periodic Benefit Cost Recognized as Expense	$ 1,933	$ 1,393	$ 541	$ 1,543	$ 2,030	$ 880

Estimated amounts expected to be amortized to net periodic benefit costs and the impact on the balance sheet during 2011 are shown in the following table:

Components	Pension Plans	Other Postretirement Benefit Plans
	(in thousands)	
Net Actuarial Loss	$ 2,846	$ 858
Prior Service Cost (Credit)	150	(35)
Total Estimated 2011 Amortization	$ 2,996	$ 823
Expected to be Recorded as		
Regulatory Asset	$ 2,996	$ 823
Total	$ 2,996	$ 823

American Electric Power System Retirement Savings Plan

KPCo participates in an AEP sponsored defined contribution retirement savings plan, the American Electric Power System Retirement Savings Plan, for substantially all employees. This qualified plan offers participants an opportunity to contribute a portion of their pay, includes features under Section 401(k) of the Internal Revenue Code and provides for matching contributions. The matching contributions to the plan were 75% of the first 6% of eligible compensation contributed by the employee in 2008. Effective January 1, 2009, the match is 100% of the first 1% of eligible employee contributions and 70% of the next 5% of contributions. The cost for contributions to the plan totaled $1.4 million in 2010, $1.7 million in 2009 and $1.6 million in 2008.

6. BUSINESS SEGMENTS

KPCo has one reportable segment, an integrated electricity generation, transmission and distribution business. KPCo's other activities are insignificant.

7. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

KPCo is exposed to certain market risks as a power producer and marketer of wholesale electricity, coal and emission allowances. These risks include commodity price risk, interest rate risk, credit risk and, to a lesser extent, foreign currency exchange risk. These risks represent the risk of loss that may impact KPCo due to changes in the underlying market prices or rates. AEPSC, on behalf of KPCo, manages these risks using derivative instruments.

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Trading Strategies

The strategy surrounding the use of derivative instruments for trading purposes focuses on seizing market opportunities to create value driven by expected changes in the market prices of the commodities in which AEPSC transacts on behalf of KPCo.

Risk Management Strategies

The strategy surrounding the use of derivative instruments focuses on managing risk exposures, future cash flows and creating value utilizing both economic and formal hedging strategies. To accomplish these objectives, AEPSC, on behalf of KPCo, primarily employs risk management contracts including physical forward purchase and sale contracts, financial forward purchase and sale contracts and financial swap instruments. Not all risk management contracts meet the definition of a derivative under the accounting guidance for "Derivatives and Hedging." Derivative risk management contracts elected normal under the normal purchases and normal sales scope exception are not subject to the requirements of this accounting guidance.

AEPSC, on behalf of KPCo, enters into power, coal, natural gas, interest rate and, to a lesser degree, heating oil and gasoline, emission allowance and other commodity contracts to manage the risk associated with the energy business. AEPSC, on behalf of KPCo, enters into interest rate derivative contracts in order to manage the interest rate exposure associated with KPCo's commodity portfolio. For disclosure purposes, such risks are grouped as "Commodity," as these risks are related to energy risk management activities. AEPSC, on behalf of KPCo, also engages in risk management of interest rate risk associated with debt financing and foreign currency risk associated with future purchase obligations denominated in foreign currencies. The amount of risk taken is determined by the Commercial Operations and Finance groups in accordance with the established risk management policies as approved by the Finance Committee of AEP's Board of Directors.

The following table represents the gross notional volume of KPCo's outstanding derivative contracts as of December 31, 2010 and 2009:

Notional Volume of Derivative Instruments

	Volume December 31, 2010	Volume December 31, 2009	Unit of Measure
	(in thousands)		
Commodity:			
Power	40,277	38,509	MWHs
Coal	3,280	2,230	Tons
Natural Gas	449	3,600	MMBtus
Heating Oil and Gasoline	274	306	Gallons
Interest Rate	$ 2,008	$ 4,239	USD

Fair Value Hedging Strategies

AEPSC, on behalf of KPCo, enters into interest rate derivative transactions as part of an overall strategy to manage the mix of fixed-rate and floating-rate debt. Certain interest rate derivative transactions effectively modify KPCo's exposure to interest rate risk by converting a portion of KPCo's fixed-rate debt to a floating rate. Provided specific criteria are met, these interest rate derivatives are designated as fair value hedges.

Cash Flow Hedging Strategies

AEPSC, on behalf of KPCo, enters into and designates as cash flow hedges certain derivative transactions for the purchase and sale of power, coal, natural gas and heating oil and gasoline ("Commodity") in order to manage the variable price risk related to the forecasted purchase and sale of these commodities. Management monitors the potential impacts of commodity price changes and, where appropriate, enters into derivative transactions to protect profit margins for a portion of future electricity sales and fuel or energy purchases. KPCo does not hedge all commodity price risk.

KPCo's vehicle fleet is exposed to gasoline and diesel fuel price volatility. AEPSC, on behalf of KPCo, enters into financial heating oil and gasoline derivative contracts in order to mitigate price risk of future fuel purchases. For disclosure purposes, these contracts are included with other hedging activity as "Commodity." KPCo does not hedge all fuel price risk.

AEPSC, on behalf of KPCo, enters into a variety of interest rate derivative transactions in order to manage interest rate risk exposure. Some interest rate derivative transactions effectively modify exposure to interest rate risk by converting a portion of floating-rate debt to a fixed rate. AEPSC, on behalf of KPCo, also enters into interest rate derivative contracts to manage interest rate exposure related to anticipated borrowings of fixed-rate debt. The anticipated fixed-rate debt offerings have a high probability of occurrence as the proceeds will be used to fund existing debt maturities and projected capital expenditures. KPCo does not hedge all interest rate exposure.

At times, KPCo is exposed to foreign currency exchange rate risks primarily because some fixed assets are purchased from foreign suppliers. In accordance with AEP's risk management policy, AEPSC, on behalf of KPCo, may enter into foreign currency derivative transactions to protect against the risk of increased cash outflows resulting from a foreign currency's appreciation against the dollar. KPCo does not hedge all foreign currency exposure.

ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND THE IMPACT ON KPCo's FINANCIAL STATEMENTS

The accounting guidance for "Derivatives and Hedging" requires recognition of all qualifying derivative instruments as either assets or liabilities on the balance sheet at fair value. The fair values of derivative instruments accounted for using MTM accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data and assumptions. In order to determine the relevant fair values of the derivative instruments, KPCo applies valuation adjustments for discounting, liquidity and credit quality.

Credit risk is the risk that a counterparty will fail to perform on the contract or fail to pay amounts due. Liquidity risk represents the risk that imperfections in the market will cause the price to vary from estimated fair value based upon prevailing market supply and demand conditions. Since energy markets are imperfect and volatile, there are inherent risks related to the underlying assumptions in models used to fair value risk management contracts. Unforeseen events may cause reasonable price curves to differ from actual price curves throughout a contract's term and at the time a contract settles. Consequently, there could be significant adverse or favorable effects on future net income and cash flows if market prices are not consistent with management's estimates of current market consensus for forward prices in the current period. This is particularly true for longer term contracts. Cash flows may vary based on market conditions, margin requirements and the timing of settlement of KPCo's risk management contracts.

According to the accounting guidance for "Derivatives and Hedging," KPCo reflects the fair values of derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, KPCo is required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the December 31, 2010 and 2009 balance sheets, KPCo netted $400 thousand and $800 thousand, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and $3.4 million and $6.4 million, respectively, of cash collateral paid to third parties against short-term and long-term risk management liabilities.

The following tables represent the gross fair value impact of KPCo's derivative activity on the Balance Sheets as of December 31, 2010 and 2009:

Fair Value of Derivative Instruments
December 31, 2010

	Risk Management Contracts	Hedging Contracts			
Balance Sheet Location	**Commodity (a)**	**Commodity (a)**	**Interest Rate (a)**	**Other (a) (b)**	**Total**
		(in thousands)			
Current Risk Management Assets	$ 60,231	$ 418	$ -	$ (51,952)	$ 8,697
Long-term Risk Management Assets	16,978	148	-	(9,096)	8,030
Total Assets	77,209	566	-	(61,048)	16,727
Current Risk Management Liabilities	59,107	490	-	(53,638)	5,959
Long-term Risk Management Liabilities	13,265	146	-	(11,108)	2,303
Total Liabilities	72,372	636	-	(64,746)	8,262
Total MTM Derivative Contract Net Assets (Liabilities)	$ 4,837	$ (70)	$ -	$ 3,698	$ 8,465

Fair Value of Derivative Instruments
December 31, 2009

	Risk Management Contracts	Hedging Contracts			
Balance Sheet Location	**Commodity (a)**	**Commodity (a)**	**Interest Rate (a)**	**Other (a) (b)**	**Total**
		(in thousands)			
Current Risk Management Assets	$ 66,858	$ 748	$ -	$ (53,919)	$ 13,687
Long-term Risk Management Assets	26,571	-	-	(17,073)	9,498
Total Assets	93,429	748	-	(70,992)	23,185
Current Risk Management Liabilities	62,216	1,024	-	(58,050)	5,190
Long-term Risk Management Liabilities	23,879	16	-	(19,794)	4,101
Total Liabilities	86,095	1,040	-	(77,844)	9,291
Total MTM Derivative Contract Net Assets (Liabilities)	$ 7,334	$ (292)	$ -	$ 6,852	$ 13,894

(a) Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented on the Balance Sheets on a net basis in accordance with the accounting guidance for "Derivatives and Hedging."
(b) Amounts represent counterparty netting of risk management and hedging contracts, associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging" and dedesignated risk management contracts.

The table below presents KPCo's activity of derivative risk management contracts for the years ended December 31, 2010 and 2009:

Amount of Gain (Loss) Recognized on
Risk Management Contracts
Years Ended December 31, 2010 and 2009

Location of Gain (Loss)	2010	2009
	(in thousands)	
Electric Generation, Transmission and Distribution Revenues	$ 10,188	$ 20,402
Sales to AEP Affiliates	(1,272)	(2,162)
Regulatory Assets (a)	(93)	-
Regulatory Liabilities (a)	(2,170)	(2,719)
Total Gain on Risk Management Contracts	$ 6,653	$ 15,521

(a) Represents realized and unrealized gains and losses subject to regulatory accounting treatment recorded as either current or non-current on the balance sheet.

Certain qualifying derivative instruments have been designated as normal purchase or normal sale contracts, as provided in the accounting guidance for "Derivatives and Hedging." Derivative contracts that have been designated as normal purchases or normal sales under that accounting guidance are not subject to MTM accounting treatment and are recognized on the Statements of Income on an accrual basis.

KPCo's accounting for the changes in the fair value of a derivative instrument depends on whether it qualifies for and has been designated as part of a hedging relationship and further, on the type of hedging relationship. Depending on the exposure, management designates a hedging instrument as a fair value hedge or a cash flow hedge.

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Realized gains and losses on derivative instruments held for trading purposes are included in revenues on a net basis on KPCo's Statements of Income. Realized gains and losses on derivative instruments not held for trading purposes are included in revenues or expenses on KPCo's Statements of Income depending on the relevant facts and circumstances. Unrealized and some realized gains and losses for both trading and non-trading derivative instruments are recorded as regulatory assets (for losses) or regulatory liabilities (for gains), in accordance with the accounting guidance for "Regulated Operations."

Accounting for Fair Value Hedging Strategies

For fair value hedges (i.e. hedging the exposure to changes in the fair value of an asset, liability or an identified portion thereof attributable to a particular risk), the gain or loss on the derivative instrument as well as the offsetting gain or loss on the hedged item associated with the hedged risk affects Net Income during the period of change.

KPCo records realized and unrealized gains or losses on interest rate swaps that qualify for fair value hedge accounting treatment and any offsetting changes in the fair value of the debt being hedged in Interest Expense on KPCo's Statements of Income. During 2010, 2009 and 2008, KPCo did not employ any fair value hedging strategies.

Accounting for Cash Flow Hedging Strategies

For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows that is attributable to a particular risk), KPCo initially reports the effective portion of the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income (Loss) on the Balance Sheets until the period the hedged item affects Net Income. KPCo records hedge ineffectiveness as a regulatory asset (for losses) or a regulatory liability (for gains).

Realized gains and losses on derivative contracts for the purchase and sale of power, coal, natural gas and heating oil and gasoline designated as cash flow hedges are included in Revenues, Fuel and Other Consumables Used for Electric Generation or Purchased Electricity for Resale on KPCo's Statements of Income, or in Regulatory Assets or Regulatory Liabilities on KPCo's Balance Sheets, depending on the specific nature of the risk being hedged. During 2010 and 2009, KPCo designated commodity derivatives as cash flow hedges.

KPCo reclassifies gains and losses on financial fuel derivative contracts designated as cash flow hedges from Accumulated Other Comprehensive Income (Loss) on its Balance Sheets into Other Operation expense, Maintenance expense or Depreciation and Amortization expense, as it relates to capital projects, on the Statements of Income. During 2010 and 2009, KPCo designated cash flow hedging strategies for forecasted fuel purchases.

KPCo reclassifies gains and losses on interest rate derivative hedges related to debt financings from Accumulated Other Comprehensive Income (Loss) into Interest Expense in those periods in which hedged interest payments occur. During 2010, 2009 and 2008, KPCo did not employ any cash flow hedging strategies for interest rates.

The accumulated gains or losses related to foreign currency hedges are reclassified from Accumulated Other Comprehensive Income (Loss) on KPCo's Balance Sheets into Depreciation and Amortization expense on the Statements of Income over the depreciable lives of the fixed assets that were designated as the hedged items in qualifying foreign currency hedging relationships. During 2010, 2009 and 2008, KPCo did not employ any foreign currency hedging strategies.

During 2010, 2009 and 2008, hedge ineffectiveness was immaterial or nonexistent for all hedge strategies disclosed above.

The following tables provide details on designated, effective cash flow hedges included in AOCI on KPCo's Balance Sheets and the reasons for changes in cash flow hedges for the years ended December 31, 2010 and 2009. All amounts in the following table are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
Year Ended December 31, 2010

	Commodity	Interest Rate	Total
		(in thousands)	
Balance in AOCI as of December 31, 2009	$ (138)	$ (463)	$ (601)
Changes in Fair Value Recognized in AOCI	(294)	-	(294)
Amount of (Gain) or Loss Reclassified from AOCI to Income Statement/within Balance Sheet:			
Electric Generation, Transmission and Distribution Revenues	44	-	44
Purchased Electricity for Resale	390	-	390
Other Operation Expense	(14)	-	(14)
Maintenance Expense	(17)	-	(17)
Interest Expense	-	60	60
Property, Plant and Equipment	(19)	-	(19)
Balance in AOCI as of December 31, 2010	$ (48)	$ (403)	$ (451)

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
Year Ended December 31, 2009

	Commodity	Interest Rate	Total
		(in thousands)	
Balance in AOCI as of December 31, 2008	$ 584	$ (525)	$ 59
Changes in Fair Value Recognized in AOCI	(152)	-	(152)
Amount of (Gain) or Loss Reclassified from AOCI to Income Statement/within Balance Sheet:			
Electric Generation, Transmission and Distribution Revenues	(1,564)	-	(1,564)
Fuel and Other Consumables Used for Electric Generation	(23)	-	(23)
Purchased Electricity for Resale	1,032	-	1,032
Interest Expense	-	62	62
Property, Plant and Equipment	(15)	-	(15)
Balance in AOCI as of December 31, 2009	$ (138)	$ (463)	$ (601)

During 2008, KPCo reclassified $320 thousand of gains from AOCI to net income.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's Balance Sheets at December 31, 2010 and 2009 were:

Impact of Cash Flow Hedges on the Balance Sheet
December 31, 2010

	Commodity	Interest Rate	Total
		(in thousands)	
Hedging Assets (a)	$ 81	$ -	$ 81
Hedging Liabilities (a)	(151)	-	(151)
AOCI Loss Net of Tax	(48)	(403)	(451)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	(48)	(60)	(108)

Impact of Cash Flow Hedges on the Balance Sheet
December 31, 2009

	Commodity	Interest Rate	Total
		(in thousands)	
Hedging Assets (a)	$ 422	$ -	$ 422
Hedging Liabilities (a)	(714)	-	(714)
AOCI Loss Net of Tax	(138)	(463)	(601)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	(127)	(60)	(187)

(a) Hedging Assets and Hedging Liabilities are included in Risk Management Assets and Liabilities on KPCo's Balance Sheets.

The actual amounts that KPCo reclassifies from Accumulated Other Comprehensive Income (Loss) to Net Income can differ from the estimate above due to market price changes. As of December 31, 2010, the maximum length of time that KPCo is hedging (with contracts subject to the accounting guidance for "Derivatives and Hedging") exposure to variability in future cash flows related to forecasted transactions is 41 months.

Credit Risk

AEPSC, on behalf of KPCo, limits credit risk in KPCo's wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. AEPSC, on behalf of KPCo, uses Moody's, Standard and Poor's and current market-based qualitative and quantitative data as well as financial statements to assess the financial health of counterparties on an ongoing basis.

AEPSC, on behalf of KPCo, uses standardized master agreements which may include collateral requirements. These master agreements facilitate the netting of cash flows associated with a single counterparty. Cash, letters of credit and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. The collateral agreements require a counterparty to post cash or letters of credit in the event an exposure exceeds the established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with AEP's credit policy. In addition, collateral agreements allow for termination and liquidation of all positions in the event of a failure or inability to post collateral.

Collateral Triggering Events

Under the tariffs of the RTOs and Independent System Operators (ISOs) and a limited number of derivative and non-derivative contracts primarily related to competitive retail auction loads, KPCo is obligated to post an additional amount of collateral if certain credit ratings decline below investment grade. The amount of collateral required fluctuates based on market prices and total exposure. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these collateral triggering items in contracts. Management does not anticipate a downgrade below investment grade. The following table represents: (a) the aggregate fair value of such derivative contracts, (b) the amount of collateral KPCo would have been required to post for all derivative and non-derivative contracts if the credit ratings had declined below investment grade and (c) how much was attributable to RTO and ISO activities as of December 31, 2010 and 2009:

	December 31, 2010	December 31, 2009
	(in thousands)	
Liabilities for Derivative Contracts with Credit Downgrade Triggers	$ 1,368	$ 449
Amount of Collateral KPCo Would Have Been Required to Post	2,614	1,699
Amount Attributable to RTO and ISO Activities	2,608	1,601

In addition, a majority of KPCo's non-exchange traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event under outstanding debt in excess of $50 million. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-default provisions in the contracts. Management does not anticipate a non-performance event under these provisions. The following table represents: (a) the fair value of these derivative liabilities subject to cross-default provisions prior to consideration of contractual netting arrangements, (b) the amount this exposure has been reduced by cash collateral posted by KPCo and (c) if a cross-default provision would have been triggered, the settlement amount that would be required after considering KPCo's contractual netting arrangements as of December 31, 2010 and 2009:

	December 31, 2010	December 31, 2009
	(in thousands)	
Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	$ 15,930	$ 31,215
Amount of Cash Collateral Posted	1,376	628
Additional Settlement Liability if Cross Default Provision is Triggered	4,926	6,537

8. FAIR VALUE MEASUREMENTS

Fair Value Measurements of Long-term Debt

The fair values of Long-term Debt are based on quoted market prices, without credit enhancements, for the same or similar issues and the current interest rates offered for instruments with similar maturities. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that could be realized in a current market exchange.

The book values and fair values of KPCo's Long-term Debt as of December 31, 2010 and 2009 are summarized in the following table:

	December 31, 2010		December 31, 2009	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
Long-term Debt	$ 548,888	$ 628,623	$ 548,722	$ 599,909

Fair Value Measurements of Financial Assets and Liabilities

For a discussion of fair value accounting and the classification of assets and liabilities within the fair value hierarchy, see the "Fair Value Measurements of Assets and Liabilities" section of Note 1.

The following tables set forth, by level within the fair value hierarchy, KPCo's financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2010 and 2009. As required by the accounting guidance for "Fair Value Measurements and Disclosures," financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There have not been any significant changes in management's valuation techniques.

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2010

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (c)	$ 350	$ 73,753	$ 2,862	$ (61,018)	$ 15,947
Cash Flow Hedges:					
Commodity Hedges (a)	-	549	-	(468)	81
Dedesignated Risk Management Contracts (b)	-	-	-	699	699
Total Risk Management Assets	$ 350	$ 74,302	$ 2,862	$ (60,787)	$ 16,727
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (c)	$ 343	$ 69,996	$ 1,789	$ (64,017)	$ 8,111
Cash Flow Hedges:					
Commodity Hedges (a)	-	619	-	(468)	151
Total Risk Management Liabilities	$ 343	$ 70,615	$ 1,789	$ (64,485)	$ 8,262

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2009

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a)	$ 472	$ 90,327	$ 2,592	$ (72,387)	$ 21,004
Cash Flow Hedges:					
Commodity Hedges (a)	-	748	-	(326)	422
Dedesignated Risk Management Contracts (b)	-	-	-	1,759	1,759
Total Risk Management Assets	$ 472	$ 91,075	$ 2,592	$ (70,954)	$ 23,185
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a)	$ 533	$ 84,831	$ 693	$ (78,030)	$ 8,027
Cash Flow Hedges:					
Commodity Hedges (a)	-	1,040	-	(326)	714
DETM Assignment (d)	-	-	-	550	550
Total Risk Management Liabilities	$ 533	$ 85,871	$ 693	$ (77,806)	$ 9,291

(a) Amounts in "Other" column primarily represent counterparty netting of risk management and hedging contracts and associated cash collateral under the accounting guidance for "Derivatives and Hedging."
(b) Represents contracts that were originally MTM but were subsequently elected as normal under the accounting guidance for "Derivatives and Hedging." At the time of the normal election, the MTM value was frozen and no longer fair valued. This MTM value will be amortized into revenues over the remaining life of the contracts.
(c) Substantially comprised of power contracts.
(d) See "Natural Gas Contracts with DETM" section of Note 12.

There have been no transfers between Level 1 and Level 2 during the year ended December 31, 2010.

The following tables set forth a reconciliation of changes in the fair value of net trading derivatives and other investments classified as Level 3 in the fair value hierarchy:

Year Ended December 31, 2010		Net Risk Management Assets (Liabilities)
		(in thousands)
Balance as of December 31, 2009	$	1,899
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)		361
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)		-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income		-
Purchases, Issuances and Settlements (c)		(1,496)
Transfers into Level 3 (d) (h)		232
Transfers out of Level 3 (e) (h)		(2,283)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)		2,360
Balance as of December 31, 2010	$	1,073

Year Ended December 31, 2009		Net Risk Management Assets (Liabilities)
		(in thousands)
Balance as of December 31, 2008	$	1,713
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)		(283)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)		-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income		-
Purchases, Issuances and Settlements (c)		(1,118)
Transfers in and/or out of Level 3 (f)		(103)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)		1,690
Balance as of December 31, 2009	$	1,899

Year Ended December 31, 2008		Net Risk Management Assets (Liabilities)
		(in thousands)
Balance as of December 31, 2007	$	(157)
Realized (Gain) Loss Included in Net Income (or Changes in Net Assets) (a)		95
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)		-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income		-
Purchases, Issuances and Settlements		-
Transfers in and/or out of Level 3 (f)		(192)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)		1,967
Balance as of December 31, 2008	$	1,713

(a) Included in revenues on KPCo's Statements of Income.
(b) Represents the change in fair value between the beginning of the reporting period and the settlement of the risk management commodity contract.
(c) Represents the settlement of risk management commodity contracts for the reporting period.
(d) Represents existing assets or liabilities that were previously categorized as Level 2.
(e) Represents existing assets or liabilities that were previously categorized as Level 3.
(f) Represents existing assets or liabilities that were either previously categorized as a higher level for which the inputs to the model became unobservable or assets and liabilities that were previously classified as Level 3 for which the lowest significant input became observable during the period.
(g) Relates to the net gains (losses) of those contracts that are not reflected on KPCo's Statements of Income. These net gains (losses) are recorded as regulatory assets/liabilities.
(h) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.

9. INCOME TAXES

The details of income taxes as reported are as follows:

	Years Ended December 31, 2010	2009	2008
		(in thousands)	
Income Tax Expense (Credit):			
Current	$ 17,767	$ (40,140)	$ 4,674
Deferred	1,075	50,612	4,097
Deferred Investment Tax Credits	(704)	(822)	(875)
Total Income Taxes	$ 18,138	$ 9,650	$ 7,896

The following is a reconciliation of the difference between the amount of federal income taxes computed by multiplying book income before income taxes by the federal statutory rate and the amount of income taxes reported.

	Years Ended December 31, 2010	2009	2008
		(in thousands)	
Net Income	$ 35,282	$ 23,936	$ 24,531
Income Taxes	18,138	9,650	7,896
Pretax Income	$ 53,420	$ 33,586	$ 32,427
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 18,697	$ 11,755	$ 11,349
Increase (Decrease) in Income Taxes resulting from the following items:			
Depreciation	1,479	2,256	1,169
AFUDC	(720)	(626)	(872)
Removal Costs	(1,364)	(1,465)	(4,110)
Investment Tax Credits, Net	(704)	(822)	(875)
State and Local Income Taxes	2,069	(2,938)	1,072
Other	(1,319)	1,490	163
Total Income Taxes	$ 18,138	$ 9,650	$ 7,896
Effective Income Tax Rate	34.0 %	28.7 %	24.4 %

The following table shows elements of the net deferred tax liability and significant temporary differences:

	December 31, 2010	2009
	(in thousands)	
Deferred Tax Assets	$ 29,149	$ 29,427
Deferred Tax Liabilities	(351,734)	(341,896)
Net Deferred Tax Liabilities	$ (322,585)	$ (312,469)
Property-Related Temporary Differences	$ (239,361)	$ (234,969)
Amounts Due from Customers for Future Federal Income Taxes	(28,545)	(27,057)
Deferred State Income Taxes	(41,855)	(36,564)
Deferred Income Taxes on Other Comprehensive Loss	243	324
Accrued Pensions	9,285	9,994
Regulatory Assets	(23,129)	(22,694)
All Other, Net	777	(1,503)
Net Deferred Tax Liabilities	$ (322,585)	$ (312,469)

KPCo joins in the filing of a consolidated federal income tax return with its affiliates in the AEP System. The allocation of the AEP System's current consolidated federal income tax to the AEP System companies allocates the benefit of current tax losses to the AEP System companies giving rise to such losses in determining their current tax expense. The tax benefit of the Parent is allocated to its subsidiaries with taxable income. With the exception of the loss of the Parent, the method of allocation reflects a separate return result for each company in the consolidated group.

KPCo and other AEP subsidiaries are no longer subject to U.S. federal examination for years before 2001. KPCo and other AEP subsidiaries have completed the exam for the years 2001 through 2006 and have issues that are being pursued at the appeals level. The years 2007 and 2008 are currently under examination. Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for federal income taxes have been made for potential liabilities resulting from such matters. In addition, KPCo accrues interest on these uncertain tax positions. Management is not aware of any issues for open tax years that upon final resolution are expected to have a material adverse effect on net income.

KPCo, along with other AEP subsidiaries, files income tax returns in various state and local jurisdictions. These taxing authorities routinely examine the tax returns and KPCo and other AEP subsidiaries are currently under examination in several state and local jurisdictions. Management believes that previously filed tax returns have positions that may be challenged by these tax authorities. However, management believes that adequate provisions for income taxes have been made for potential liabilities resulting from such challenges and that the ultimate resolution of these audits will not materially impact net income. With few exceptions, KPCo is no longer subject to state or local income tax examinations by tax authorities for years before 2000.

KPCo sustained federal, state and local net income tax operating losses in 2009 driven primarily by bonus depreciation, a change in tax accounting method related to units of property and other book versus tax temporary differences. As a result, KPCo accrued current federal, state and local income tax benefits in 2009. KPCo realized the federal cash flow in 2010 as there was sufficient capacity in prior periods to carry the consolidated federal net operating loss back. Most of KPCo's state and local jurisdictions do not provide for a net operating loss carry back. However it is anticipated that future taxable income will be sufficient to realize the tax benefit. As such, management has determined that a valuation allowance is unnecessary.

KPCo recognizes interest accruals related to uncertain tax positions in interest income or expense as applicable, and penalties in Other Operation in accordance with the accounting guidance for "Income Taxes."

The following table shows amounts reported for interest expense, interest income and reversal of prior period interest expense:

	Year Ended December 31,		
	2010	**2009**	**2008**
		(in thousands)	
Interest Expense	$ 439	$ 1,113	$ 303
Interest Income	-	-	1,863
Reversal of Prior Period Interest Expense	320	39	-

The following table shows balances for amounts accrued for the receipt of interest and the payment of interest and penalties:

	December 31,	
	2010	**2009**
	(in thousands)	
Accrual for Receipt of Interest	$ 475	$ 416
Accrual for Payment of Interest and Penalties	566	722

The reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

	2010	2009	2008
		(in thousands)	
Balance at January 1,	$ 2,553	$ 3,345	$ 2,205
Increase - Tax Positions Taken During a Prior Period	970	2,178	-
Decrease - Tax Positions Taken During a Prior Period	(97)	(2,757)	(113)
Increase - Tax Positions Taken During the Current Year	-	-	1,301
Decrease - Tax Positions Taken During the Current Year	(202)	(141)	(144)
Increase - Settlements with Taxing Authorities	-	-	96
Decrease - Settlements with Taxing Authorities	(513)	-	-
Decrease - Lapse of the Applicable Statute of Limitations	-	(72)	-
Balance at December 31,	$ 2,711	$ 2,553	$ 3,345

The total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate is $184 thousand, $528 thousand and $881 thousand for 2010, 2009 and 2008, respectively. Management believes there will be no significant net increase or decrease in unrecognized tax benefits within 12 months of the reporting date.

Federal Tax Legislation

The Economic Stimulus Act of 2008 provided enhanced expensing provisions for certain assets placed in service in 2008 and a 50% bonus depreciation provision similar to the one in effect in 2003 through 2004 for assets placed in service in 2008. The enacted provisions did not have a material impact on KPCo's net income or financial condition, but provided a cash flow benefit of approximately $10 million.

The Patient Protection and Affordable Care Act and the related Health Care and Education Reconciliation Act (Health Care Acts) were enacted in March 2010. The Health Care Acts amend tax rules so that the portion of employer health care costs that are reimbursed by the Medicare Part D prescription drug subsidy will no longer be deductible by the employer for federal income tax purposes effective for years beginning after December 31, 2012. Because of the loss of the future tax deduction, a reduction in the deferred tax asset related to the nondeductible OPEB liabilities accrued to date was recorded by KPCo in March 2010. This reduction, which was offset by recording net tax regulatory assets, did not materially affect KPCo's net income, cash flows or financial condition for the year ended December 31, 2010.

The Small Business Jobs Act (the Act) was enacted in September 2010. Included in the Act was a one-year extension of the 50% bonus depreciation provision. The Tax Relief, Unemployment Insurance Reauthorization and the Job Creation Act of 2010 extended the life of research and development, employment and several energy tax credits originally scheduled to expire at the end of 2010. In addition, the Act extended the time for claiming bonus depreciation and increased the deduction to 100% for part of 2010 and 2011. The enacted provisions will not have a material impact on KPCo's net income or financial condition but had a favorable impact on cash flows of approximately $8 million in 2010.

The American Recovery and Reinvestment Tax Act of 2009 provided for several new grant programs and expanded tax credits and an extension of the 50% bonus depreciation provision enacted in the Economic Stimulus Act of 2008. The enacted provisions did not have a material impact on KPCo's net income or financial condition. However, the bonus depreciation contributed to AEP's 2009 federal net operating tax loss and resulted in a 2010 cash flow benefit to KPCo of approximately $20 million.

State Tax Legislation

Michigan Senate Bill 0094 (MBT Act), effective January 1, 2008, provided a comprehensive restructuring of Michigan's principal business tax. The law replaced the Michigan Single Business Tax. The MBT Act is composed of a new tax which will be calculated based upon two components: (a) a business income tax (BIT) imposed at a rate of 4.95% and (b) a modified gross receipts tax (GRT) imposed at a rate of 0.80%, which will collectively be referred to as the BIT/GRT tax calculation. The law also includes significant credits for engaging in Michigan-based activity.

In March 2008, legislation was signed providing for, among other things, a reduction in the West Virginia corporate income tax rate from 8.75% to 8.5% beginning in 2009. The corporate income tax rate could also be reduced to 7.75% in 2012 and 7% in 2013 contingent upon the state government achieving certain minimum levels of shortfall reserve funds. Management has evaluated the impact of the law change and the application of the law change will not materially impact KPCo's net income, cash flows or financial condition.

10. LEASES

Leases of property, plant and equipment are for periods up to 20 years and require payments of related property taxes, maintenance and operating costs. The majority of the leases have purchase or renewal options and will be renewed or replaced by other leases.

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

Lease Rental Costs	Years Ended December 31, 2010	2009	2008
		(in thousands)	
Net Lease Expense on Operating Leases	$ 836	$ 1,948	$ 2,250
Amortization of Capital Leases	1,673	746	971
Interest on Capital Leases	304	53	102
Total Lease Rental Costs	$ 2,813	$ 2,747	$ 3,323

The following table shows the property, plant and equipment under capital leases and related obligations recorded on KPCo's Balance Sheets. Capital lease obligations are included in Other Current Liabilities and Deferred Credits and Other Noncurrent Liabilities on KPCo's Balance Sheets.

	December 31, 2010	2009
	(in thousands)	
Property, Plant and Equipment Under Capital Leases		
Generation	$ 683	$ 504
Other Property, Plant and Equipment	6,511	2,876
Total Property, Plant and Equipment Under Capital Leases	7,194	3,380
Accumulated Amortization	1,781	1,627
Net Property, Plant and Equipment Under Capital Leases	$ 5,413	$ 1,753
Obligations Under Capital Leases		
Noncurrent Liability	$ 3,569	$ 1,113
Liability Due Within One Year	1,844	640
Total Obligations Under Capital Leases	$ 5,413	$ 1,753

Future minimum lease payments consisted of the following at December 31, 2010:

Future Minimum Lease Payments	Capital Leases	Noncancelable Operating Leases
	(in thousands)	
2011	$ 2,088	$ 791
2012	1,533	771
2013	1,284	728
2014	351	529
2015	300	399
Later Years	472	896
Total Future Minimum Lease Payments	$ 6,028	$ 4,114
Less Estimated Interest Element	615	
Estimated Present Value of Future Minimum Lease Payments	$ 5,413	

Master Lease Agreements

KPCo leases certain equipment under master lease agreements. In December 2010, management signed a new master lease agreement with GE Capital Commercial Inc. (GE) to replace existing operating and capital leases with GE. These assets were included in existing master lease agreements that were to be terminated in 2011 since GE exercised the termination provision related to these leases in 2008. Certain assets were not included in the refinancing, but the assets will be purchased or refinanced in 2011. In addition, certain operating leases that were previously under lease with GE are now recorded as capital leases after the refinancing. The amounts refinanced for KPCo are as follows:

Leases Refinanced with GE	KPCo
	(in thousands)
Operating Lease to Operating Lease	$ 3,246
Capital Lease to Capital Lease	314
Operating Lease to Capital Lease	1,142

These obligations are included in the future minimum lease payments schedule earlier in this note.

For equipment under the GE master lease agreements, the lessor is guaranteed receipt of up to 84% of the unamortized balance of the equipment at the end of the lease term. If the fair value of the leased equipment is below the unamortized balance at the end of the lease term, KPCo is committed to pay the difference between the fair value and the unamortized balance, with the total guarantee not to exceed 84% of the unamortized balance. For equipment under other master lease agreements, the lessor is guaranteed a residual value up to a stated percentage of either the unamortized balance or the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, KPCo is committed to pay the difference between the actual fair value and the residual value guarantee. At December 31, 2010, the maximum potential loss for these lease agreements was approximately $481 thousand ($312 thousand net of tax) assuming the fair value of the equipment is zero at the end of the lease term. Historically, at the end of the lease term the fair value has been in excess of the unamortized balance.

11. FINANCING ACTIVITIES

Long-term Debt

There are certain limitations on establishing liens against KPCo's assets under its indentures. None of the long-term debt obligations of KPCo have been guaranteed or secured by AEP or any of its affiliates.

The following details long-term debt outstanding as of December 31, 2010 and 2009:

Type of Debt	Maturity	Weighted Average Interest rate at December 31, 2010	Interest Rate Ranges at December 31, 2010	Interest Rate Ranges at December 31, 2009	Outstanding at December 31, 2010	Outstanding at December 31, 2009
					(in thousands)	
Senior Unsecured Notes	2017-2039	6.40%	5.625%-8.13%	5.625%-8.13%	$ 530,000	$ 530,000
Notes Payable - Affiliated	2015	5.25%	5.25%	5.25%	20,000	20,000
Unamortized Discount (net)					(1,112)	(1,278)
Total Long-term Debt Outstanding					548,888	548,722
Less Portion Due Within One Year					-	-
Long-term Portion					$ 548,888	$ 548,722

Long-term debt outstanding at December 31, 2010 is payable as follows:

	2011	2012	2013	2014	2015	After 2015	Total
				(in thousands)			
Principal Amount	$ -	$ -	$ -	$ -	$ 20,000	$ 530,000	$ 550,000
Unamortized Discount							(1,112)
Total Long-term Debt Outstanding							$ 548,888

Dividend Restrictions

Federal Power Act

The Federal Power Act prohibits KPCo from participating "in the making or paying of any dividends of such public utility from any funds properly included in capital account." The term "capital account" is not defined in the Federal Power Act or its regulations. Management understands "capital account" to mean the par value of the common stock multiplied by the number of shares outstanding. This restriction does not limit the ability of KPCo to pay dividends out of retained earnings.

Leverage Restrictions

Pursuant to credit agreement leverage restrictions, at December 31, 2010, none of the retained earnings of KPCo have restrictions related to the payment of dividends.

Utility Money Pool – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of its subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds the utility subsidiaries. The AEP System Utility Money Pool operates in accordance with the terms and conditions approved in a regulatory order. The amount of outstanding loans (borrowings) to/from the Utility Money Pool as of December 31, 2010 and 2009 is included in Advances to/from Affiliates on KPCo's balance sheets. KPCo's Utility Money Pool activity and corresponding authorized borrowing limits for the years ended December 31, 2010 and 2009 are described in the following table:

Year	Maximum Borrowings from Utility Money Pool	Maximum Loans to Utility Money Pool	Average Borrowings from Utility Money Pool	Average Loans to Utility Money Pool	Loans (Borrowings) to/from Utility Money Pool as of December 31,	Authorized Short-Term Borrowing Limit
			(in thousands)			
2010	$ 18,963	$ 69,599	$ 5,857	$ 25,995	$ 67,060	$ 250,000
2009	174,108	19,775	113,764	7,589	(485)	250,000

Maximum, minimum and average interest rates for funds either borrowed from or loaned to the Utility Money Pool for the years ended December 31, 2010, 2009 and 2008 are summarized in the following table:

Year Ended December 31,	Maximum Interest Rates for Funds Borrowed from Utility Money Pool	Minimum Interest Rates for Funds Borrowed from Utility Money Pool	Maximum Interest Rates for Funds Loaned to Utility Money Pool	Minimum Interest Rates for Funds Loaned to Utility Money Pool	Average Interest Rates for Funds Borrowed from Utility Money Pool	Average Interest Rates for Funds Loaned to Utility Money Pool
2010	0.55 %	0.09 %	0.53 %	0.09 %	0.38 %	0.31 %
2009	2.28 %	0.18 %	0.63 %	0.15 %	1.33 %	0.35 %
2008	5.47 %	2.28 %	- %	- %	3.42 %	- %

Interest expense and interest income related to the Utility Money Pool are included in Interest Expense and Interest Income, respectively, on KPCo's Statements of Income. For amounts borrowed from and advanced to the Utility Money Pool, KPCo incurred the following amounts of interest expense and earned the following amounts of interest income, respectively, for the years ended December 31, 2010, 2009 and 2008:

	Years Ended December 31, 2010	2009	2008
		(in thousands)	
Interest Expense	$ 10	$ 983	$ 1,893
Interest Income	49	18	-

Credit Facilities

In June 2010, KPCo and certain other companies in the AEP System reduced a $627 million credit agreement that matures in April 2011 to $478 million. Under the facility, letters of credit may be issued. As of December 31, 2010, there were no outstanding amounts for KPCo under the facility.

Sale of Receivables – AEP Credit

Under a sale of receivables arrangement, KPCo sells, without recourse, certain of its customer accounts receivable and accrued unbilled revenue balances to AEP Credit and is charged a fee based on AEP Credit's financing costs, administrative costs and uncollectible accounts experience for KPCo's receivables. The costs of customer accounts receivable sold are reported in Other Operation on KPCo's income statement. KPCo manages and services its accounts receivable sold.

In July 2010, AEP Credit renewed its receivables securitization agreement. The agreement provides a commitment of $750 million from bank conduits to purchase receivables. A commitment of $375 million expires in July 2011 and the remaining commitment of $375 million expires in July 2013.

KPCo's amount of accounts receivable and accrued unbilled revenues sold under the sale of receivables agreement was $63 million, $41 million and $56 million as of December 31, 2010, 2009 and 2008, respectively.

The fees paid by KPCo to AEP Credit for customer accounts receivable sold were $2 million, $2 million and $3 million for the years ended December 31, 2010, 2009 and 2008, respectively.

KPCo's proceeds on the sale of receivables to AEP Credit were $548 million, $500 million and $485 million as of December 31, 2010, 2009 and 2008, respectively.

12. RELATED PARTY TRANSACTIONS

For other related party transactions, also see "Utility Money Pool – AEP System" and "Sale of Receivables – AEP Credit" sections of Note 11.

AEP Power Pool

APCo, CSPCo, I&M, KPCo and OPCo are parties to the Interconnection Agreement, dated July 6, 1951, as amended, defining how they share the costs and benefits associated with their generating plants. This sharing is based upon each company's MLR, which is calculated monthly on the basis of each company's maximum peak demand in relation to the sum of the maximum peak demands of all five companies during the preceding 12 months. In December 2010, each AEP Power Pool member gave notice to AEPSC and the other AEP Power Pool members of its decision to terminate the Interconnection Agreement effective January 2014 or such other date approved by the FERC. It is unknown at this time what will replace the Interconnection Agreement. In addition, since 1995, APCo, CSPCo, I&M, KPCo and OPCo have been parties to the AEP System Interim Allowance Agreement, which provides, among other things, for the transfer of SO_2 allowances associated with the transactions under the Interconnection Agreement.

Power, gas and risk management activities are conducted by AEPSC and profits and losses are allocated under the SIA to AEP Power Pool members, PSO and SWEPCo. Risk management activities involve the purchase and sale of electricity and gas under physical forward contracts at fixed and variable prices. In addition, the risk management of electricity, and to a lesser extent gas contracts, includes exchange traded futures and options and OTC 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. In addition, AEPSC enters into transactions for the purchase and sale of electricity and gas options, futures and swaps, and for the forward purchase and sale of electricity outside of the AEP System's traditional marketing area.

CSW Operating Agreement

PSO, SWEPCo and AEPSC are parties to a Restated and Amended Operating Agreement originally dated as of January 1, 1997 (CSW Operating Agreement), which was approved by the FERC. The CSW Operating Agreement requires PSO and SWEPCo to maintain adequate annual planning reserve margins and requires that capacity in excess of the required margins be made available for sale to other operating companies as capacity commitments. Parties are compensated for energy delivered to recipients based upon the deliverer's incremental cost plus a portion of the recipient's savings realized by the purchaser that avoids the use of more costly alternatives. Revenues and costs arising from third party sales are generally shared based on the amount of energy PSO or SWEPCo contributes that is sold to third parties.

System Integration Agreement (SIA)

The SIA provides for the integration and coordination of AEP East companies' and AEP West companies' zones. This includes joint dispatch of generation within the AEP System and the distribution, between the two zones, of costs and benefits associated with the transfers of power between the two zones (including sales to third parties and risk management and trading activities). The SIA is designed to function as an umbrella agreement in addition to the Interconnection Agreement and the CSW Operating Agreement, each of which controls the distribution of costs and benefits within a zone.

Power generated, allocated or provided under the Interconnection Agreement or CSW Operating Agreement is primarily sold to customers at rates approved by the public utility commission in the jurisdiction of sale.

Under both the Interconnection Agreement and CSW Operating Agreement, power generated that is not needed to serve the AEP System's native load is sold in the wholesale market by AEPSC on behalf of the generating subsidiary.

Affiliated Revenues and Purchases

The following table shows the revenues derived from sales to the pools, direct sales to affiliates, natural gas contracts with AEPES and other revenues for the years ended December 31, 2010, 2009 and 2008:

	Years Ended December 31,		
Related Party Revenues	**2010**	**2009**	**2008**
		(in thousands)	
Sales to AEP Power Pool	$ 57,777	$ 64,074	$ 62,642
Direct Sales to West Affiliates	711	454	3,521
Direct Sales to Transmission Companies	737	-	-
Natural Gas Contracts with AEPES	(435)	(1,823)	(133)
Other Revenues	1,215	(92)	219
Total Affiliated Revenues	$ 60,005	$ 62,613	$ 66,249

The following table shows the purchased power expense incurred from purchases from the pools and affiliates for the years ended December 31, 2010, 2009 and 2008:

	Years Ended December 31,		
Related Party Purchases	**2010**	**2009**	**2008**
		(in thousands)	
Purchases from AEP Power Pool	$ 107,199	$ 96,284	$ 127,669
Direct Purchases from West Affiliates	169	305	454
Purchases from AEGCo	101,032	101,731	106,256
Total Purchases	$ 208,400	$ 198,320	$ 234,379

The above summarized related party revenues and expenses are reported as Sales to AEP Affiliates and Purchased Electricity from AEP Affiliates on KPCo's Statements of Income.

System Transmission Integration Agreement

AEP's System Transmission Integration Agreement provides for the integration and coordination of the planning, operation and maintenance of the transmission facilities of AEP East companies' and AEP West companies' zones. Similar to the SIA, the System Transmission Integration Agreement functions as an umbrella agreement in addition to the Transmission Agreement (TA) and the Transmission Coordination Agreement (TCA). The System Transmission Integration Agreement contains two service schedules that govern:

- The allocation of transmission costs and revenues and
- The allocation of third-party transmission costs and revenues and AEP System dispatch costs.

The System Transmission Integration Agreement anticipates that additional service schedules may be added as circumstances warrant.

APCo, CSPCo, I&M, KPCo and OPCo are parties to the TA, dated April 1, 1984, as amended, defining how they share the costs associated with their relative ownership of the extra-high-voltage transmission system (facilities rated 345 kV and above) and certain facilities operated at lower voltages (138 kV and above). Like the Interconnection Agreement, this sharing is based upon each company's MLR. The FERC approved a new TA effective November 2010. The impacts of the new TA will be phased-in for retail rates, adds KGPCo and WPCo as parties to the agreement and changes the allocation method.

KPCo's net credits as allocated under the TA during the years ended December 31, 2010, 2009 and 2008 were $8 million, $9 million and $2 million, respectively, and were recorded in Other Operation expense on KPCo's Statements of Income.

PSO, SWEPCo, TCC, TNC and AEPSC are parties to the TCA, originally dated January 1, 1997, as amended. The TCA has been approved by the FERC and establishes a coordinating committee, which is charged with overseeing the coordinated planning of the transmission facilities of the AEP West companies.

Natural Gas Contracts with DETM

In 2003, AEPES assigned to AEPSC, as agent for the AEP East companies, approximately $97 million (negative value) associated with its natural gas contracts with DETM. The assignment was executed in order to consolidate DETM positions within AEP. Beginning in 2007, PSO and SWEPCo were allocated a portion of the DETM assignment based on the SIA methodology of sharing trading and marketing margins between the AEP East companies, PSO and SWEPCo. Concurrently, in order to ensure that there would be no financial impact to the AEP East companies, PSO or SWEPCo as a result of the assignment, AEPES and AEPSC entered into agreements requiring AEPES to reimburse AEPSC for any related cash settlements and all income related to the assigned contracts. The agreement between AEPSC and AEPES ended December 31, 2010, coinciding with the settlement of the remaining DETM contracts. KPCo's risk management liabilities related to DETM at December 31, 2009 was $550 thousand.

Fuel Agreement between OPCo and AEPES

OPCo and National Power Cooperative, Inc (NPC) have an agreement whereby OPCo operates a 500 MW gas plant owned by NPC (Mone Plant). AEPES entered into a fuel management agreement with OPCo and NPC to manage and procure fuel for the Mone Plant. The gas purchased by AEPES and used in generation is first sold to OPCo then allocated to the AEP East companies, who have an agreement to purchase 100% of the available generating capacity from the plant through May 2012. KPCo's related purchases of gas managed by AEPES were $195 thousand, $88 thousand and $257 thousand for the years ended December 31, 2010, 2009 and 2008, respectively. These purchases are reflected in Purchased Electricity for Resale on KPCo's Statements of Income.

Unit Power Agreements (UPA)

A UPA between AEGCo and I&M (the I&M Power Agreement) provides for the sale by AEGCo to I&M of all the power (and the energy associated therewith) available to AEGCo at the Rockport Plant unless it is sold to another utility. I&M is obligated, whether or not power is available from AEGCo, to pay as a demand charge for the right to receive such power (and as an energy charge for any associated energy taken by I&M) net of amounts received by AEGCo from any other sources, sufficient to enable AEGCo to pay all its operating and other expenses, including a rate of return on the common equity of AEGCo as approved by the FERC. The I&M Power Agreement will continue in effect until the expiration of the lease term of Unit 2 of the Rockport Plant unless extended in specified circumstances.

Pursuant to an assignment between I&M and KPCo and a UPA between KPCo and AEGCo, AEGCo sells KPCo 30% of the power (and the energy associated therewith) available to AEGCo from both units of the Rockport Plant. KPCo pays to AEGCo in consideration for the right to receive such power the same amounts which I&M would have paid AEGCo under the terms of the I&M Power Agreement for such entitlement. The KPCo UPA ends in December 2022.

I&M Barging, Urea Transloading and Other Services

I&M provides barging, urea transloading and other transportation services to affiliates. Urea is a chemical used to control NO_x emissions at certain generation plants in the AEP System. KPCo recorded costs of $133 thousand, $112 thousand and $9 thousand in 2010, 2009 and 2008, respectively, for urea transloading provided by I&M. These costs were recorded as fuel expense or other operation expense.

Central Machine Shop

APCo operates a facility which repairs and rebuilds specialized components for the generation plants across the AEP System. APCo defers on its balance sheet the cost of performing the services, then transfers the cost to the affiliate for reimbursement. KPCo recorded these billings as capital or maintenance expense depending on the nature of the services received. These billings are recoverable from customers. KPCo's billed amounts were $368 thousand, $358 thousand and $1.2 million for the years ended December 31, 2010, 2009 and 2008, respectively.

Affiliate Coal Purchases

In 2008, OPCo entered into contracts to sell excess coal purchases to certain AEP subsidiaries through 2010. KPCo's purchases are reflected in Sales to AEP Affiliates on its Statements of Income. KPCo's realized and unrealized losses recorded for the years ended December 31, 2010, 2009 and 2008 were $837 thousand, $340 thousand and $36 thousand, respectively.

Affiliate Railcar Agreement

KPCo has an agreement providing for the use its of affiliates' leased or owned railcars when available. The agreement specifies that the company using the railcar will be billed, at cost, by the company furnishing the railcar. KPCo recorded these costs in Fuel on its Balance Sheets and such costs are recoverable from customers. The following table shows the net effect of the railcar agreement on KPCo's Balance Sheets:

	December 31,	
Billing Company	**2010**	**2009**
	(in thousands)	
APCo	$ 399	$ 669
OPCo	245	13

AEP Power Pool Purchases from OVEC

Beginning in 2006, the AEP Power Pool began purchasing power from OVEC as part of wholesale marketing and risk management activity. These purchases are reflected in Electric Generation, Transmission and Distribution revenues in KPCo's Statements of Income. The agreement ended in December 2008. KPCo recorded $4 million for the year ended December 31, 2008.

In January 2010, the AEP Power Pool began purchasing power from OVEC to serve off-system sales and retail sales through June 2010. Purchases serving off-system sales are reported net as a reduction in Electric Generation, Transmission and Distribution revenues and purchases serving retail sales are reported in Purchased Electricity for Resale expenses on KPCo's Statement of Income. KPCo recorded $1.4 million in revenue and $743 thousand in expense for the year ended December 31, 2010.

Sales and Purchases of Property

KPCo had affiliated sales and purchases of electric property individually amounting to $100 thousand or more for the years ended December 31, 2010, 2009 and 2008 as shown in the following table:

Companies	2010	2009	2008
		(in thousands)	
APCo to KPCo	$ 209	$ -	$ -
CSP to KPCo	433	-	-
I&M to KPCo	-	-	444
OPCo to KPCo	527	-	-

Years Ended December 31,

In addition, KPCo had aggregate affiliated sales and purchases of meters and transformers for the years ended December 31, 2010, 2009 and 2008 as shown in the following table:

	APCo	CSPCo	I&M	KGPCo	OPCo	PSO	SWEPCo	TCC	WPCo	Total
Sales					(in thousands)					
2010	$ 364	$ 9	$ 6	$ 23	$ 83	$ -	$ 2	$ -	$ -	$ 487
2009	505	23	64	7	133	3	8	-	1	744
2008	354	11	16	6	121	-	2	33	-	543
Purchases										
2010	139	-	7	-	139	-	3	-	-	288
2009	161	-	50	-	87	-	26	-	-	324
2008	112	-	15	-	95	-	-	-	-	222

The amounts above are recorded in Property, Plant and Equipment. Transfers are recorded at cost.

Global Borrowing Notes

AEP has an intercompany note in place with KPCo. The debt is reflected in Long-term Debt – Affiliated on KPCo's Balance Sheets. KPCo accrues interest for its share of the global borrowing and remits the interest to AEP. The accrued interest is reflected in Accrued Interest on KPCo's Balance Sheets. KPCo participates in the global borrowing arrangement.

Intercompany Billings

KPCo performs certain utility services for other AEP subsidiaries when necessary or practical. The costs of these services are billed on a direct-charge basis, whenever possible, or on reasonable bases of proration for services that benefit multiple companies. The billings for services are made at cost and include no compensation for the use of equity capital. Billings are capitalized or expensed depending on the nature of the services rendered.

Variable Interest Entities

The accounting guidance for "Variable Interest Entities" is a consolidation model that considers if a company has a controlling financial interest in a VIE. A controlling financial interest will have both (a) the power to direct the activities of a VIE that most significantly impact the VIE's economic performance and (b) the obligation to absorb losses of the VIE that could potentially be significant to the VIE or the right to receive benefits from the VIE that could potentially be significant to the VIE. Entities are required to consolidate a VIE when it is determined that they have a controlling financial interest in a VIE and therefore, are the primary beneficiary of that VIE, as defined by the accounting guidance for "Variable Interest Entities." In determining whether KPCo is the primary beneficiary of a VIE, management considers factors such as equity at risk, the amount of the VIE's variability KPCo absorbs, guarantees of indebtedness, voting rights including kick-out rights, power to direct the VIE and other factors. Management believes that significant assumptions and judgments were applied consistently. There have been no changes to the reporting of VIEs in the financial statements where it is concluded that KPCo is the primary beneficiary. In addition, KPCo has not provided financial or other support to any VIE that was not previously contractually required.

AEPSC provides certain managerial and professional services to KPCo and other subsidiaries. AEP is the sole equity owner of AEPSC. AEP management controls the activities of AEPSC. The costs of the services are based on a direct charge or on a prorated basis and billed to KPCo and other subsidiaries at AEPSC's cost. KPCo and other subsidiaries have not provided financial or other support outside the reimbursement of costs for services rendered. AEPSC finances its operations through cost reimbursement from other AEP subsidiaries. There are no other terms or arrangements between AEPSC and KPCo and other subsidiaries that could require additional financial support from KPCo and other subsidiaries or expose them to losses outside of the normal course of business. AEPSC and its billings are subject to regulation by the FERC. KPCo and other subsidiaries are exposed to losses to the extent they cannot recover the costs of AEPSC through their normal business operations. KPCo is considered to have a significant interest in AEPSC due to its activity in AEPSC's cost reimbursement structure. However, KPCo does not have control over AEPSC. AEPSC is consolidated by AEP. In the event AEPSC would require financing or other support outside the cost reimbursement billings, this financing would be provided by AEP. Total billings from AEPSC for the years ended December 31, 2010, 2009 and 2008 were $37 million, $34 million and $46 million, respectively. The carrying amount of liabilities associated with AEPSC for the years ended December 31, 2010 and 2009 were $3 million and $4 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

AEGCo, a wholly-owned subsidiary of AEP, is consolidated by AEP. AEGCo owns a 50% ownership interest in Rockport Plant Unit 1 and leases a 50% interest in Rockport Plant Unit 2. AEGCo sells all the output from the Rockport Plant to I&M and KPCo. AEP guarantees all the debt obligations of AEGCo. KPCo is considered to have a significant interest in AEGCo due to its transactions. KPCo is exposed to losses to the extent it cannot recover the costs of AEGCo through its normal business operations. Due to AEP management's control over AEGCo, KPCo is not considered the primary beneficiary of AEGCo. In the event AEGCo would require financing or other support outside the billings to KPCo, this financing would be provided by AEP. Total billings from AEGCo for the years ended December 31, 2010, 2009 and 2008 were $101 million, $102 million and $106 million, respectively. The carrying amount of liabilities associated with AEGCo for the years ended December 31, 2010 and 2009 was $10 million and $9 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

13. PROPERTY, PLANT AND EQUIPMENT

Depreciation

KPCo provides for depreciation of Property, Plant and Equipment on a straight-line basis over the estimated useful lives of property, generally using composite rates by functional class. The following table provides the annual composite depreciation rates by functional class:

2010	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Generation	$ 553,589	$ 200,199	3.8%	40-50	$ -	$ -	-	-
Transmission	444,303	148,466	1.7%	25-75	-	-	-	-
Distribution	590,606	171,092	3.5%	11-75	-	-	-	-
CWIP	34,093	(880)	N.M.	N.M.	-	-	-	-
Other	58,282	23,371	8.3%	N.M.	5,700	195	N.M.	N.M.
Total	$ 1,680,873	$ 542,248			$ 5,700	$ 195		

2009	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Generation	$ 547,378	$ 190,020	3.8%	40-50	$ -	$ -	-	-
Transmission	438,775	142,966	1.7%	25-75	-	-	-	-
Distribution	569,389	156,181	3.4%	11-75	-	-	-	-
CWIP	28,409	(3,767)	N.M.	N.M.	-	-	-	-
Other	53,504	23,218	9.7%	N.M.	5,498	188	N.M.	N.M.
Total	$ 1,637,455	$ 508,618			$ 5,498	$ 188		

2008	Regulated		Nonregulated	
Functional Class of Property	Annual Composite Depreciation Rate	Depreciable Life Ranges	Annual Composite Depreciation Rate	Depreciable Life Ranges
		(in years)		(in years)
Generation	3.5%	40-50	-	-
Transmission	1.6%	25-75	-	-
Distribution	3.4%	11-75	-	-
CWIP	N.M.	N.M.	-	-
Other	8.1%	N.M.	N.M.	N.M.

N.M. Not Meaningful

The composite depreciation rate generally includes a component for nonasset retirement obligation (non-ARO) removal costs, which is credited to Accumulated Depreciation and Amortization. Actual removal costs incurred are charged to Accumulated Depreciation and Amortization. Any excess of accrued non-ARO removal costs over actual removal costs incurred is reclassified from Accumulated Depreciation and Amortization and reflected as a regulatory liability.

Asset Retirement Obligations (ARO)

KPCo records ARO in accordance with the accounting guidance for "Asset Retirement and Environmental Obligations" for the retirement of asbestos removal. KPCo has identified, but not recognized, ARO liabilities related to electric transmission and distribution assets, as a result of certain easements on property on which assets are owned. Generally, such easements are perpetual and require only the retirement and removal of assets upon the cessation of the property's use. The retirement obligation is not estimable for such easements since KPCo plans to use its facilities indefinitely. The retirement obligation would only be recognized if and when KPCo abandons or ceases the use of specific easements, which is not expected.

The following is a reconciliation of the 2010 and 2009 aggregate carrying amounts of ARO for KPCo:

Year	ARO at January 1,	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates	ARO at December 31,
			(in thousands)			
2010	$ 3,506	$ 292	$ 823	$ (435)	$ -	$ 4,186
2009	3,275	297	-	(66)	-	3,506

Allowance for Funds Used During Construction (AFUDC)

KPCo's amounts of allowance for borrowed and equity funds used during construction are summarized in the following table:

	Years Ended December 31, 2010	2009	2008
		(in thousands)	
Allowance for Equity Funds Used During Construction	$ 768	$ 391	$ 1,012
Allowance for Borrowed Funds Used During Construction	594	394	1,701

14. COST REDUCTION INITIATIVES

In April 2010, management began initiatives to decrease both labor and non-labor expenses with a goal of achieving significant reductions in operation and maintenance expenses. A total of 2,461 positions were eliminated across the AEP System as a result of process improvements, streamlined organizational designs and other efficiencies. Most of the affected employees terminated employment on May 31, 2010. The severance program provides two weeks of base pay for every year of service along with other severance benefits.

KPCo recorded a charge to expense in 2010 primarily related to the headcount reduction initiatives. Management does not expect additional costs to be incurred related to this initiative.

Expense Allocation from AEPSC	Incurred	Settled	Adjustments	Remaining Balance at December 31, 2010
		(in thousands)		
$ 3,481	$ 8,175	$ 12,001	$ 1,363	$ 1,018

These costs relate primarily to severance benefits. They are included primarily in Other Operation on the Statements of Income and Other Current Liabilities on the Balance Sheets.

15. UNAUDITED QUARTERLY FINANCIAL INFORMATION

In management's opinion, the unaudited quarterly information reflects all normal and recurring accruals and adjustments necessary for a fair presentation of the results of operations for interim periods. Quarterly results are not necessarily indicative of a full year's operations because of various factors. KPCo's unaudited quarterly financial information is as follows:

	2010 Quarterly Periods Ended			
	March 31	June 30	September 30	December 31
	(in thousands)			
Total Revenues	$ 173,918	$ 136,972	$ 189,417 (b)	$ 183,365 (b)
Operating Income (Loss)	24,680	(2,831)(a)	33,326 (b)	33,680 (b)
Net Income (Loss)	9,491	(7,045)(a)	15,945 (b)	16,891 (b)

	2009 Quarterly Periods Ended			
	March 31	June 30	September 30	December 31
	(in thousands)			
Total Revenues	$ 178,433	$ 155,099	$ 152,153	$ 146,841
Operating Income	20,053	18,144	10,923	17,669
Net Income	9,454	6,208	1,309	6,965

(a) See Note 14 for discussion of expenses related to cost reduction initiatives recorded in the second quarter of 2010.
(b) See "Kentucky Base Rate Filing" section of Note 2 for discussion of new base rates in effect.

There were no significant events in 2009.

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Economic Projections of Federal Reserve Board Members and Federal Reserve Bank Presidents, January 2012

Advance release of table 1 of the Summary of Economic Projections to be released with the FOMC minutes

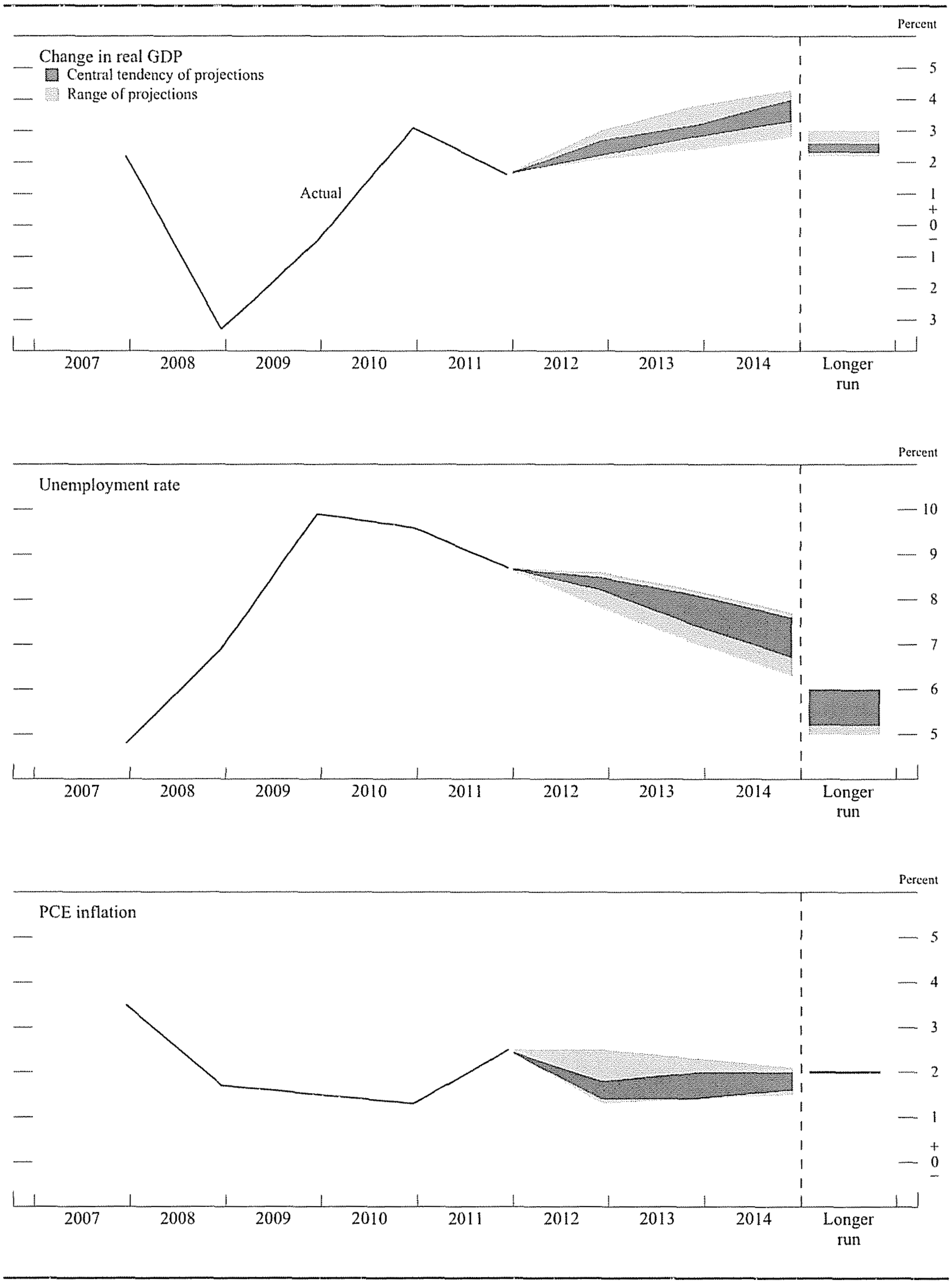
Percent

Variable	Central tendency[1]				Range[2]			
	2012	2013	2014	Longer run	2012	2013	2014	Longer run
Change in real GDP	2.2 to 2.7	2.8 to 3.2	3.3 to 4.0	2.3 to 2.6	2.1 to 3.0	2.4 to 3.8	2.8 to 4.3	2.2 to 3.0
November projection	2.5 to 2.9	3.0 to 3.5	3.0 to 3.9	2.4 to 2.7	2.3 to 3.5	2.7 to 4.0	2.7 to 4.5	2.2 to 3.0
Unemployment rate	8.2 to 8.5	7.4 to 8.1	6.7 to 7.6	5.2 to 6.0	7.8 to 8.6	7.0 to 8.2	6.3 to 7.7	5.0 to 6.0
November projection	8.5 to 8.7	7.8 to 8.2	6.8 to 7.7	5.2 to 6.0	8.1 to 8.9	7.5 to 8.4	6.5 to 8.0	5.0 to 6.0
PCE inflation	1.4 to 1.8	1.4 to 2.0	1.6 to 2.0	2.0	1.3 to 2.5	1.4 to 2.3	1.5 to 2.1	2.0
November projection	1.4 to 2.0	1.5 to 2.0	1.5 to 2.0	1.7 to 2.0	1.4 to 2.8	1.4 to 2.5	1.5 to 2.4	1.5 to 2.0
Core PCE inflation[3]	1.5 to 1.8	1.5 to 2.0	1.6 to 2.0		1.3 to 2.0	1.4 to 2.0	1.4 to 2.0	
November projection	1.5 to 2.0	1.4 to 1.9	1.5 to 2.0		1.3 to 2.1	1.4 to 2.1	1.4 to 2.2	

NOTE: Projections of change in real gross domestic product (GDP) and projections for both measures of inflation are from the fourth quarter of the previous year to the fourth quarter of the year indicated. PCE inflation and core PCE inflation are the percentage rates of change in, respectively, the price index for personal consumption expenditures (PCE) and the price index for PCE excluding food and energy. Projections for the unemployment rate are for the average civilian unemployment rate in the fourth quarter of the year indicated. Each participant's projections are based on his or her assessment of appropriate monetary policy. Longer-run projections represent each participant's assessment of the rate to which each variable would be expected to converge under appropriate monetary policy and in the absence of further shocks to the economy. The November projections were made in conjunction with the meeting of the Federal Open Market Committee on November 1–2, 2011.

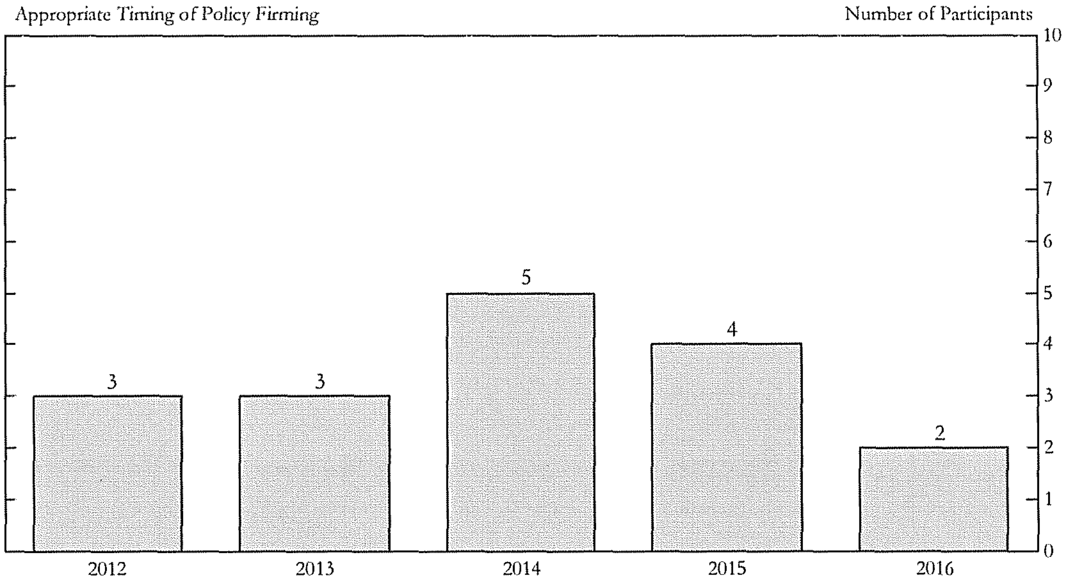
1. The central tendency excludes the three highest and three lowest projections for each variable in each year.
2. The range for a variable in a given year includes all participants' projections, from lowest to highest, for that variable in that year.
3. Longer-run projections for core PCE inflation are not collected.

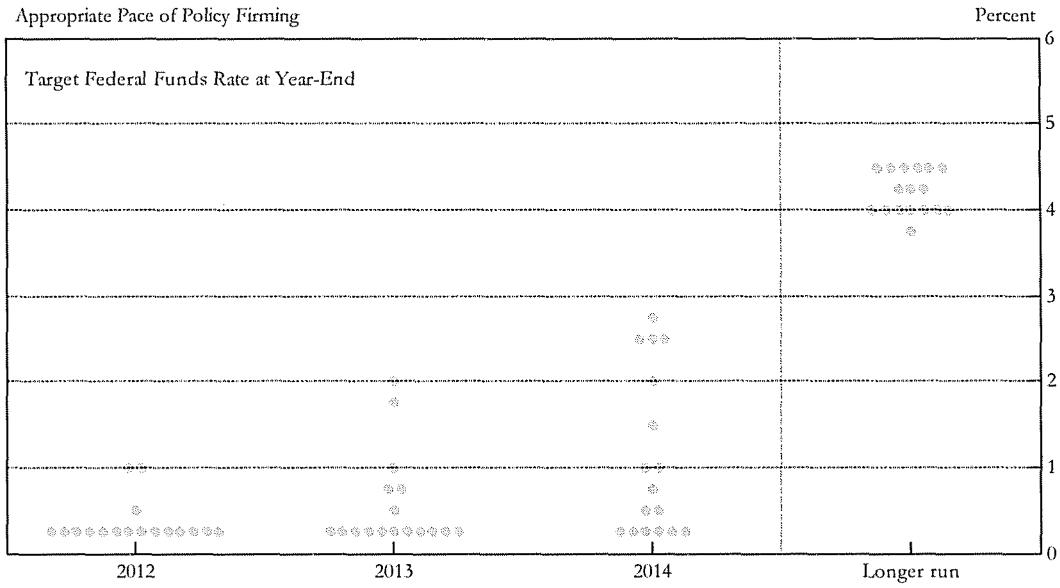
Figure 1. Central tendencies and ranges of economic projections, 2012–14 and over the longer run



NOTE: Definitions of variables are in the notes to the projections table. The data for the variables are annual. Actual fourth-quarter 2011 values for the change in real GDP and for PCE inflation have not yet been published by the Bureau of Economic Analysis; the plotted values of these variables for 2011 are the median estimates taken from the Federal Reserve Bank of New York's January survey of primary dealers.

Figure 2. Overview of FOMC participants' assessments of appropriate monetary policy





NOTE: In the upper panel, the height of each bar denotes the number of FOMC participants who judge that, under appropriate monetary policy and in the absence of further shocks to the economy, the first increase in the target federal funds rate from its current range of 0 to 1/4 percent will occur in the specified calendar year. In the lower panel, each shaded circle indicates the value (rounded to the nearest 1/4 percent) of an individual participant's judgment of the appropriate level of the target federal funds rate at the end of the specified calendar year or over the longer run.

Explanation of Economic Projections Charts

The charts show actual values and projections for three economic variables:

- Change in Real Gross Domestic Product (GDP)—as measured from the fourth quarter of the previous year to the fourth quarter of the year indicated, with values plotted at the end of each year.
- Unemployment Rate—the average civilian unemployment rate in the fourth quarter of each year, with values plotted at the end of each year.
- PCE Inflation—as measured by the change in the personal consumption expenditures (PCE) price index from the fourth quarter of the previous year to the fourth quarter of the year indicated, with values plotted at the end of each year.

Information for these variables is shown for each year from 2007 to 2014, and for the longer run.

The solid line, labeled "Actual," shows the historical values for each variable.[1]

The lightly shaded areas represent the ranges of the projections of policymakers. The bottom of the range for each variable is the lowest of all of the projections for that year or period. Likewise, the top of the range is the highest of all of the projections for that year or period.

The dark shaded areas represent the central tendency, which is a narrower version of the range that excludes the three highest and three lowest projections for each variable in each year or period.

The longer-run projections, which are shown on the far right side of the charts, are the rates of growth, unemployment, and inflation to which a policymaker expects the economy to converge over time—maybe in five or six years—in the absence of further shocks and under appropriate monetary policy. Because appropriate monetary policy, by definition, is aimed at achieving the Federal Reserve's dual mandate of maximum employment and price stability in the longer run, policymakers' longer-run projections for economic growth and unemployment may be interpreted, respectively, as estimates of the economy's normal or trend rate of growth and its normal unemployment rate over the longer run. Similarly, the longer-run projections of inflation are for the rate of inflation that each policymaker judges to be most consistent with the Federal Reserve's dual mandate in the longer term.

[1] Actual fourth-quarter 2011 values for the change in real GDP and for PCE inflation have not yet been published by the Bureau of Economic Analysis; the plotted values of these variables for 2011 are the median estimates taken from the Federal Reserve Bank of New York's January survey of primary dealers.

Explanation of Policy Path Charts

These charts are based on policymakers' projections of the appropriate path for the FOMC's target federal funds rate. The target funds rate is measured as the level of the target rate at the end of the calendar year or in the longer run. Appropriate monetary policy, by definition, is the future path of policy that each participant deems most likely to foster outcomes for economic activity and inflation that best satisfy his or her interpretation of the Federal Reserve's dual objectives of maximum employment and stable prices.

- In the upper panel, the shaded bars represent the number of FOMC participants who project that the initial increase in the target federal funds rate (from its current range of 0 to ¼ percent) would appropriately occur in the specified calendar year.
- In the lower panel, the dots represent individual policymakers' projections of the appropriate federal funds rate target at the end of each of the next several years and in the longer run. Each dot in that chart represents one policymaker's projection. Please note that for purposes of this chart the responses are rounded to the nearest ¼ percent, with the exception that all values below 37.5 basis points are rounded to ¼ percent.

These projections of the timing of the initial increase of the target federal funds rate and the path of the target federal funds rate are the ones that policymakers view as compatible with their individual economic projections.

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2010

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from _________ to_________

Commission File Number	Registrants; States of Incorporation; Address and Telephone Number	I.R.S. Employer Identification Nos.
1-3525	AMERICAN ELECTRIC POWER COMPANY, INC. (A New York Corporation)	13-4922640
1-3457	APPALACHIAN POWER COMPANY (A Virginia Corporation)	54-0124790
1-2680	COLUMBUS SOUTHERN POWER COMPANY (An Ohio Corporation)	31-4154203
1-3570	INDIANA MICHIGAN POWER COMPANY (An Indiana Corporation)	35-0410455
1-6543	OHIO POWER COMPANY (An Ohio Corporation)	31-4271000
0-343	PUBLIC SERVICE COMPANY OF OKLAHOMA (An Oklahoma Corporation)	73-0410895
1-3146	SOUTHWESTERN ELECTRIC POWER COMPANY (A Delaware Corporation)	72-0323455
	1 Riverside Plaza, Columbus, Ohio 43215	
	Telephone (614) 716-1000	

Securities registered pursuant to Section 12(b) of the Act:

Registrant	Title of each class	Name of each exchange on which registered
American Electric Power Company, Inc.	Common Stock, $6.50 par value	New York Stock Exchange
Appalachian Power Company	None	
Columbus Southern Power Company	None	
Indiana Michigan Power Company	None	
Ohio Power Company	None	
Public Service Company of Oklahoma	6% Senior Notes, Series B, Due 2032	New York Stock Exchange
Southwestern Electric Power Company	None	

Securities registered pursuant to Section 12(g) of the Act:

Registrant	Title of each class
American Electric Power Company, Inc.	None
Appalachian Power Company	4.50% Cumulative Preferred Stock, Voting, no par value
Columbus Southern Power Company	None
Indiana Michigan Power Company	None
Ohio Power Company	4.50% Cumulative Preferred Stock, Voting, $100 par value
Public Service Company of Oklahoma	None
Southwestern Electric Power Company	4.28% Cumulative Preferred Stock, Voting, $100 par value
	4.65% Cumulative Preferred Stock, Voting, $100 par value
	5.00% Cumulative Preferred Stock, Voting, $100 par value

Indicate by check mark if the registrants American Electric Power Company, Inc., and Appalachian Power Company is each a well-known seasoned issuer, as defined in Rule 405 on the Securities Act. Yes ☒ No. ☐

Indicate by check mark if the registrants Columbus Southern Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company, are well-known seasoned issuers, as defined in Rule 405 on the Securities Act. Yes ☐ No. ☒

Indicate by check mark if the registrants are not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. Yes ☐ No. ☒

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes ☒ No. ☐

Indicate by check mark whether American Electric Power Company, Inc. has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No. ☐

Indicate by check mark whether Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company have submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files). Yes ☐ No. ☐

Indicate by check mark if disclosure of delinquent filers with respect to Appalachian Power Company, Ohio Power Company, Public Service Company of Oklahoma or Southwestern Electric Power Company pursuant to Item 405 of Regulation S-K (229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements of Appalachian Power Company, Ohio Power Company, Public Service Company of Oklahoma or Southwestern Electric Power Company incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether American Electric Power Company, Inc. is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See definitions of 'large accelerated filer', 'accelerated filer' and 'smaller reporting company' in Rule 12b-2 of the Exchange Act. (Check One)

Large accelerated filer	☒	Accelerated filer	☐
Non-accelerated filer	☐ (Do not check if a smaller reporting company)	Smaller reporting company	☐

Indicate by check mark whether Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company are large accelerated filers, accelerated filers, non-accelerated filers or smaller reporting companies. See definitions of 'large accelerated filer', 'accelerated filer' and 'smaller reporting company' in Rule 12b-2 of the Exchange Act. (Check One)

Large accelerated filer	☐	Accelerated filer	☐
Non-accelerated filer	☒ (Do not check if a smaller reporting company)	Smaller reporting company	☐

Indicate by check mark if the registrants are shell companies, as defined in Rule 12b-2 of the Exchange Act. Yes ☐ No. ☒

Columbus Southern Power Company and Indiana Michigan Power Company meet the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and are therefore filing this Form 10-K with the reduced disclosure format specified in General Instruction I(2) to such Form 10-K.

	Aggregate market value of voting and non-voting common equity held by non-affiliates of the registrants as of June 30, 2010, the last trading date of the registrants' most recently completed second fiscal quarter	Number of shares of common stock outstanding of the registrants at December 31, 2010
American Electric Power Company, Inc.	$15,530,071,139	480,807,156 ($6.50 par value)
Appalachian Power Company	None	13,499,500 (no par value)
Columbus Southern Power Company	None	16,410,426 (no par value)
Indiana Michigan Power Company	None	1,400,000 (no par value)
Ohio Power Company	None	27,952,473 (no par value)
Public Service Company of Oklahoma	None	9,013,000 ($15 par value)
Southwestern Electric Power Company	None	7,536,640 ($18 par value)

Note On Market Value Of Common Equity Held By Non-Affiliates

American Electric Power Company, Inc. owns all of the common stock of Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company (see Item 12 herein).

Documents Incorporated By Reference

Description	Part of Form 10-K Into Which Document Is Incorporated
Portions of Annual Reports of the following companies for the fiscal year ended December 31, 2010: American Electric Power Company, Inc. Appalachian Power Company Columbus Southern Power Company Indiana Michigan Power Company Ohio Power Company Public Service Company of Oklahoma Southwestern Electric Power Company	Part II
Portions of Proxy Statement of American Electric Power Company, Inc. for 2011 Annual Meeting of Shareholders.	Part III
Portions of Information Statements of the following companies for 2011 Annual Meeting of Shareholders: Appalachian Power Company Ohio Power Company Public Service Company of Oklahoma Southwestern Electric Power Company	Part III

This combined Form 10-K is separately filed by American Electric Power Company, Inc., Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company. Information contained herein relating to any individual registrant is filed by such registrant on its own behalf. Except for American Electric Power Company, Inc., each registrant makes no representation as to information relating to the other registrants.

You can access financial and other information at AEP's website, including AEP's Principles of Business Conduct (which also serves as a code of ethics applicable to Item 10 of this Form 10-K), certain committee charters and Principles of Corporate Governance. The address is www.AEP.com. AEP makes available, free of charge on its website, copies of its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after filing such material electronically or otherwise furnishing it to the SEC.

TABLE OF CONTENTS

GLOSSARY OF TERMS

The following abbreviations or acronyms used in this Form 10-K are defined below:

Abbreviation or Acronym	Definition
AECC	Arkansas Electric Cooperative Corporation, an unaffiliated corporation
AEGCo	AEP Generating Company, an electric utility subsidiary of AEP
AEP or parent	American Electric Power Company, Inc.
AEP East companies	APCo, CSPCo, I&M, KPCo and OPCo
AEP Power Pool	APCo, CSPCo, I&M, KPCo and OPCo, as parties to the Interconnection Agreement
AEP River Operations	AEP's inland river transportation subsidiary, AEP River Operations LLC (formerly AEP MEMCO LLC), operating primarily on the Ohio, Illinois, and lower Mississippi rivers
AEPSC	American Electric Power Service Corporation, a service company subsidiary of AEP
AEP System or the System	The American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries
AEP West companies	PSO, SWEPCo, TCC and TNC
AEP Utilities	AEP Utilities, Inc., a subsidiary of AEP, formerly, Central and South West Corporation
AFUDC	Allowance for funds used during construction (the net cost of borrowed funds, and a reasonable rate of return on other funds, used for construction under regulatory accounting)
ALJ	Administrative law judge
APCo	Appalachian Power Company, a public utility subsidiary of AEP
APSC	Arkansas Public Service Commission
Buckeye	Buckeye Power, Inc., an unaffiliated corporation
CAA	Clean Air Act
CAAA	Clean Air Act Amendments of 1990
CCS	Carbon capture and storage technology
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act of 1980
CO_2	Carbon dioxide and other greenhouse gases
Cook Plant	The Donald C. Cook Nuclear Plant, owned by I&M, and located near Bridgman, Michigan
CSPCo	Columbus Southern Power Company, a public utility subsidiary of AEP
CSW	Central and South West Corporation, a public utility holding company that merged with AEP in June 2000.
CSW Operating Agreement	Agreement, dated January 1, 1997, as amended, originally by and among PSO, SWEPCo, TCC and TNC, currently by and between PSO and SWEPCo governing generating capacity allocation, energy pricing, and revenues and costs of third party sales. AEPSC acts as the agent for the parties.
DOE	United States Department of Energy
DP&L	The Dayton Power and Light Company, an unaffiliated utility company
Duke Ohio	Duke Energy Ohio, Inc.
EMF	Electric and Magnetic Fields
EPA	United States Environmental Protection Agency
EPACT	The Energy Policy Act of 2005
ERCOT	Electric Reliability Council of Texas
ESP	Electric Security Plans, filed with the PUCO, pursuant to the Ohio Amendments
ETEC	East Texas Electric Cooperative
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
I&M	Indiana Michigan Power Company, a public utility subsidiary of AEP
IGCC	Integrated Gasification Combined Cycle

Abbreviation or Acronym	Definition
Interconnection Agreement	Agreement, dated July 6, 1951, as amended, by and among APCo, CSPCo, I&M, KPCo and OPCo, defining the sharing of costs and benefits associated with their respective generating plants
IURC	Indiana Utility Regulatory Commission
KgPCo	Kingsport Power Company, a public utility subsidiary of AEP
KPCo	Kentucky Power Company, a public utility subsidiary of AEP
KPSC	Kentucky Public Service Commission
Lawrenceburg Plant	A 1,146 MW gas-fired unit owned by AEGCo and located near Lawrenceburg, Indiana
LLWPA	Low-Level Waste Policy Act of 1980
LPSC	Louisiana Public Service Commission
MISO	Midwest Independent Transmission System Operator
Moody's	Moody's Investors Service, Inc.
MW	Megawatt
NO_x	Nitrogen oxide
NPC	National Power Cooperatives, Inc., an unaffiliated corporation
NRC	Nuclear Regulatory Commission
NSR Consent Decree	The 2007 settlement with the Federal EPA, the United States Department of Justice, certain states and special interest groups that ended the litigation which had alleged that APCo, CSPCo, I&M and OPCo violated the new source review requirements of the CAA.
OASIS	Open Access Same-time Information System
OATT	Open Access Transmission Tariff, filed with FERC
OCC	Corporation Commission of the State of Oklahoma
Ohio Act	Ohio electric restructuring legislation
Ohio Amendments	Amendments to the Ohio Act adopted in April 2008 which required electric utilities to adjust their rates by filing an ESP with the PUCO
OPCo	Ohio Power Company, a public utility subsidiary of AEP
OSS	Off-system sales
OVEC	Ohio Valley Electric Corporation, an electric utility company in which AEP and CSPCo together own a 43.47% equity interest
PJM	PJM Interconnection, L.L.C., a regional transmission organization
PM	Particulate Matter
Power Pool	The pooled generation resources of AEP East companies established under the Interconnection Agreement
PSO	Public Service Company of Oklahoma, a public utility subsidiary of AEP
PUCO	Public Utilities Commission of Ohio
PUCT	Public Utility Commission of Texas
RCRA	Resource Conservation and Recovery Act of 1976, as amended
REP	Texas retail electricity provider
Rockport Plant	A generating plant owned and partly leased by AEGCo and I&M (two 1,300 MW, coal-fired) located near Rockport, Indiana
ROE	Return on Equity
RTO	Regional Transmission Organization
SEC	Securities and Exchange Commission
S&P	Standard & Poor's Ratings Service
SO_2	Sulfur dioxide
SPP	Southwest Power Pool
SWEPCo	Southwestern Electric Power Company, a public utility subsidiary of AEP
TA	Transmission Agreement dated April 1, 1984 by and among APCo, CSPCo, I&M, KPCo, KgPCo, OPCo and WPCo, which allocates costs and benefits in connection with the operation of transmission assets

Abbreviation or Acronym	Definition
TCA	Transmission Coordination Agreement dated January 1, 1997, restated and amended, as approved by FERC in 2002, by and among, PSO, SWEPCo, TNC and AEPSC, in connection with the operation of the transmission assets of the three public utility subsidiaries
TCC	AEP Texas Central Company, formerly Central Power and Light Company, a public utility subsidiary of AEP
Texas Act	Texas electric restructuring legislation
TNC	AEP Texas North Company, formerly West Texas Utilities Company, a public utility subsidiary of AEP
TVA	Tennessee Valley Authority
VSCC	Virginia State Corporation Commission
WPCo	Wheeling Power Company, a public utility subsidiary of AEP
WVPSC	West Virginia Public Service Commission

FORWARD-LOOKING INFORMATION

This report made by the registrants contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Many forward-looking statements appear in "Item 7—Management's Financial Discussion and Analysis," but there are others throughout this document, which may be identified by words such as "expect," "anticipate," "intend," "plan," "believe," "will," "should," "could," "would," "project," "continue," and similar expressions, and include statements reflecting future results or guidance and statements of outlook. These matters are subject to risks and uncertainties such as those below and as further described in our Risk Factors that could cause actual results to differ materially from those projected. Forward-looking statements in this document speak only as of the date of this document. Except to the extent required by applicable law, we undertake no obligation to update or revise any forward-looking statement. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are:

- The economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns.
- Inflationary or deflationary interest rate trends.
- Volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates.
- The availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material.
- Electric load, customer growth and the impact of retail competition, particularly in Ohio.
- Weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms.
- Available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters.
- Availability of necessary generating capacity and the performance of our generating plants.
- Our ability to resolve I&M's Donald C. Cook Nuclear Plant Unit 1 restoration and outage-related issues through warranty, insurance and the regulatory process.
- Our ability to recover regulatory assets and stranded costs in connection with deregulation.
- Our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates.
- Our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates.
- New legislation, litigation and government regulation, including oversight of energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants.
- Timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance).
- Resolution of litigation.
- Our ability to constrain operation and maintenance costs.
- Our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities.
- Changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market.
- Actions of rating agencies, including changes in the ratings of debt.
- Volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities.
- Changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP.
- Accounting pronouncements periodically issued by accounting standard-setting bodies.

- The impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans, captive insurance entity and nuclear decommissioning trust and the impact on future funding requirements.
- Prices and demand for power that we generate and sell at wholesale.
- Changes in technology, particularly with respect to new, developing or alternative sources of generation.
- Other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events.
- Our ability to recover through rates or prices any remaining unrecovered investment in generating units that may be retired before the end of their previously projected useful lives.

PART I

ITEM 1. BUSINESS

GENERAL

OVERVIEW AND DESCRIPTION OF SUBSIDIARIES

AEP was incorporated under the laws of the State of New York in 1906 and reorganized in 1925. It is a public utility holding company that owns, directly or indirectly, all of the outstanding common stock of its public utility subsidiaries and varying percentages of other subsidiaries.

The service areas of AEP's public utility subsidiaries cover portions of the states of Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia. The generating and transmission facilities of AEP's public utility subsidiaries are interconnected and their operations are coordinated. Transmission networks are interconnected with extensive distribution facilities in the territories served. The public utility subsidiaries of AEP have traditionally provided electric service, consisting of generation, transmission and distribution, on an integrated basis to their retail customers. Restructuring legislation in Michigan, Ohio, and the ERCOT area of Texas has caused AEP public utility subsidiaries in those states to unbundle previously integrated regulated rates for their retail customers.

The AEP System is an integrated electric utility system. As a result, the member companies of the AEP System have contractual, financial and other business relationships with the other member companies, such as participation in the AEP System savings and retirement plans and tax returns, sales of electricity and transportation and handling of fuel. The companies of the AEP System also obtain certain accounting, administrative, information systems, engineering, financial, legal, maintenance and other services at cost from a common provider, AEPSC.

At December 31, 2010, the subsidiaries of AEP had a total of 18,712 employees. Because it is a holding company rather than an operating company, AEP has no employees. The public utility subsidiaries of AEP are:

APCo (organized in Virginia in 1926) is engaged in the generation, transmission and distribution of electric power to approximately 957,000 retail customers in the southwestern portion of Virginia and southern West Virginia, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. At December 31, 2010, APCo and its wholly owned subsidiaries had 2,186 employees. Among the principal industries served by APCo are paper, rubber, coal mining, textile mill products and stone, clay and glass products. In addition to its AEP System interconnections, APCo is interconnected with the following unaffiliated utility companies: Carolina Power & Light Company, Duke Carolina and Virginia Electric and Power Company. APCo has several points of interconnection with TVA and has entered into agreements with TVA under which APCo and TVA interchange and transfer electric power over portions of their respective systems. APCo is a member of PJM.

CSPCo (organized in Ohio in 1937, the earliest direct predecessor company having been organized in 1883) is engaged in the generation, transmission and distribution of electric power to approximately 749,000 retail customers in Ohio, and in supplying and marketing electric power at wholesale to other electric utilities, municipalities and other market participants. At December 31, 2010, CSPCo had 1,082 employees. CSPCo's service area is comprised of two areas in Ohio, which include portions of twenty-five counties. One area includes the City of Columbus and the other is a predominantly rural area in south central Ohio. Among the principal industries served are primary metals, chemicals and allied products, health services and electronic machinery. In January 2011, CSPCo and OPCo filed an application with the FERC requesting approval for CSPCo to merge into OPCo, effective in October 2011. Decisions are pending from the PUCO and the FERC. In addition to its AEP System interconnections, CSPCo is interconnected with the following unaffiliated utility companies: Duke Ohio, DP&L and Ohio Edison Company. CSPCo is a member of PJM.

I&M (organized in Indiana in 1925) is engaged in the generation, transmission and distribution of electric power to approximately 582,000 retail customers in northern and eastern Indiana and southwestern Michigan, and in supplying and marketing electric power at wholesale to other electric utility companies, rural electric cooperatives, municipalities and other market participants. At December 31, 2010, I&M had 2,705 employees. Among the principal industries served are primary metals, transportation equipment, electrical and electronic machinery, fabricated metal products, rubber and chemicals and allied products, rubber products and transportation equipment. Since 1975, I&M has leased and operated the assets of the municipal system of the City of Fort Wayne, Indiana. Subject to regulatory approval, I&M has agreed to purchase these assets. In addition to its AEP System interconnections, I&M is interconnected with the following unaffiliated utility companies: Central Illinois Public Service Company, Duke Ohio, Commonwealth Edison Company, Consumers Energy Company, Illinois Power Company, Indianapolis Power & Light Company, Louisville Gas and Electric Company, Northern Indiana Public Service Company, Duke Indiana and Richmond Power & Light Company. I&M is a member of PJM.

KPCo (organized in Kentucky in 1919) is engaged in the generation, transmission and distribution of electric power to approximately 174,000 retail customers in an area in eastern Kentucky, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. At December 31, 2010, KPCo had 417 employees. Among the principal industries served are petroleum refining, coal mining and chemical production. In addition to its AEP System interconnections, KPCo is interconnected with the following unaffiliated utility companies: Kentucky Utilities Company and East Kentucky Power Cooperative Inc. KPCo is also interconnected with TVA. KPCo is a member of PJM.

KgPCo (organized in Virginia in 1917) provides electric service to approximately 47,000 retail customers in Kingsport and eight neighboring communities in northeastern Tennessee. Kingsport Power Company does not own any generating facilities and is a member of PJM. It purchases electric power from APCo for distribution to its customers. At December 31, 2010, Kingsport Power Company had 52 employees.

OPCo (organized in Ohio in 1907 and re-incorporated in 1924) is engaged in the generation, transmission and distribution of electric power to approximately 706,000 retail customers in the northwestern, east central, eastern and southern sections of Ohio, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. At December 31, 2010, OPCo had 2,100 employees. Among the principal industries served by OPCo are primary metals, chemical manufacturing, petroleum refining, and rubber and plastic products. In January 2011, CSPCo and OPCo filed an application with the FERC requesting approval for CSPCo to merge into OPCo, effective in October 2011. Decisions are pending from the PUCO and the FERC. In addition to its AEP System interconnections, OPCo is interconnected with the following unaffiliated utility companies: Duke Ohio, The Cleveland Electric Illuminating Company, DP&L, Duquesne Light Company, Kentucky Utilities Company, Monongahela Power Company, Ohio Edison Company, The Toledo Edison Company and West Penn Power Company. OPCo is a member of PJM.

PSO (organized in Oklahoma in 1913) is engaged in the generation, transmission and distribution of electric power to approximately 532,000 retail customers in eastern and southwestern Oklahoma, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. At December 31, 2010, PSO had 1,150 employees. Among the principal industries served by PSO are paper manufacturing and timber products, natural gas and oil extraction, transportation, non-metallic mineral production, oil refining and steel processing, In addition to its AEP System interconnections, PSO is interconnected with Empire District Electric Company, Oklahoma Gas and Electric Company, Southwestern Public Service Company and Westar Energy, Inc. PSO is a member of SPP.

SWEPCo (organized in Delaware in 1912) is engaged in the generation, transmission and distribution of electric power to approximately 520,000 retail customers in northeastern and panhandle of Texas, northwestern Louisiana and western Arkansas, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. At December 31, 2010, SWEPCo had 1,382 employees. Among the principal industries served by SWEPCo are natural gas and oil production, petroleum refining, manufacturing of pulp and paper, chemicals, food processing, and metal refining. The territory served by SWEPCo also includes several military installations, colleges and universities.

SWEPCO also owns and operates a lignite coal mining operation. In addition to its AEP System interconnections, SWEPCo is interconnected with Cleco Corp., Empire District Electric Co., Entergy Corp. and Oklahoma Gas & Electric Co. SWEPCo is a member of SPP.

TCC (organized in Texas in 1945) is engaged in the transmission and distribution of electric power to approximately 775,000 retail customers through REPs in southern Texas. TCC has sold all of its generation assets. At December 31, 2010, TCC had 1,006 employees. Among the principal industries served by TCC are chemical and petroleum refining, chemicals and allied products, oil and gas extraction, food processing, metal refining, plastics, and machinery equipment. In addition to its AEP System interconnections, TCC is a member of ERCOT.

TNC (organized in Texas in 1927) is engaged in the transmission and distribution of electric power to approximately 186,000 retail customers through REPs in west and central Texas. TNC's generating capacity has been transferred to an affiliate at TNC's cost pursuant to an agreement effective through 2027. At December 31, 2010, TNC had 319 employees. Among the principal industries served by TNC are petroleum refining, agriculture and the manufacturing or processing of cotton seed products, oil products, precision and consumer metal products, meat products and gypsum products. The territory served by TNC also includes several military installations and correctional facilities. In addition to its AEP System interconnections, TNC is a member of ERCOT.

WPCo (organized in West Virginia in 1883 and reincorporated in 1911) provides electric service to approximately 41,000 retail customers in northern West Virginia. WPCo does not own any generating facilities. WPCo is a member of PJM. It purchases electric power from OPCo for distribution to its customers. At December 31, 2010, WPCo had 52 employees.

AEGCo (organized in Ohio in 1982) is an electric generating company. AEGCo sells power at wholesale to I&M, CSPCo and KPCo. AEGCo has no employees.

SERVICE COMPANY SUBSIDIARY

AEP also owns a service company subsidiary, AEPSC. AEPSC provides accounting, administrative, information systems, engineering, financial, legal, maintenance and other services at cost to the AEP affiliated companies. The executive officers of AEP and certain of its public utility subsidiaries are employees of AEPSC. At December 31, 2010, AEPSC had 5,132 employees.

CLASSES OF SERVICE

The principal classes of service from which the public utility subsidiaries of AEP derive revenues and the amount of such revenues during the year ended December 31, 2010 are as follows:

Description	AEP System (a)	APCo	CSPCo	I&M
	(in thousands)			
UTILITY OPERATIONS:				
Retail Sales				
Residential Sales	$ 5,125,000	$ 1,221,563	$ 883,766	$ 496,605
Commercial Sales	3,406,000	559,718	751,724	364,908
Industrial Sales	2,840,000	653,762	254,342	400,140
PJM Net Charges	(42,000)	(14,008)	(7,852)	(7,998)
Provision for Rate Refund	(52,000)	4,147	(50,000)	-
Other Retail Sales	207,000	74,331	7,053	6,610
Total Retail	11,484,000	2,499,513	1,839,033	1,260,265
Wholesale				
Off-System Sales	1,812,000	439,689	223,799	474,472
Transmission	181,000	(20,518)	(14,399)	(139)
Total Wholesale	1,993,000	419,171	209,400	474,333
Other Electric Revenues	145,000	31,499	14,822	740
Other Operating Revenues	65,000	8,713	2,792	15,368
Sales to Affiliates	-	316,207	82,994	445,021
Total Utility Operating Revenues	13,687,000	3,275,103	2,149,041	2,195,727
OTHER	740,000	-	-	-
TOTAL REVENUES	$ 14,427,000	$ 3,275,103	$ 2,149,041	$ 2,195,727

(a) Includes revenues of other subsidiaries not shown. Intercompany transactions have been eliminated for the year ended December 31, 2010.

Description	OPCo	PSO	SWEPCo
	(in thousands)		
UTILITY OPERATIONS:			
Retail Sales			
Residential Sales	$ 735,551	$ 523,997	$ 496,454
Commercial Sales	464,770	337,856	392,193
Industrial Sales	660,952	222,087	275,229
PJM Net Charges	(9,295)	-	-
Provision for Rate Refund	-	(55)	(6,375)
Other Retail Sales	10,957	72,125	7,800
Total Retail	1,862,935	1,156,010	1,165,301
Wholesale			
Off-System Sales	311,246	46,364	240,935
Transmission	(16,288)	30,039	44,336
Total Wholesale	294,958	76,403	285,271
Other Electric Revenues	1,313	14,503	18,942
Other Operating Revenues	17,509	3,218	2,150
Sales to Affiliates	1,046,992	23,528	51,870
Total Utility Operating Revenues	3,223,707	1,273,662	1,523,534
OTHER	-	-	-
TOTAL REVENUES	$ 3,223,707	$ 1,273,662	$ 1,523,534

FINANCING

General

Companies within the AEP System generally use short-term debt to finance working capital needs. Short-term debt is also used to finance acquisitions, construction and redemption or repurchase of outstanding securities until such needs can be financed with long-term debt. In recent history, short-term funding needs have been provided for by cash on hand, borrowing under AEP's revolving credit agreements and AEP's commercial paper program. Funds are made available to subsidiaries under the AEP corporate borrowing program. Certain public utility subsidiaries of AEP also sell accounts receivable to provide liquidity. See *Management's Financial Discussion and Analysis*, included in the 2010 Annual Reports, under the heading entitled *Financial Condition* for additional information concerning short-term funding and our access to bank lines of credit, commercial paper and capital markets.

AEP's revolving credit agreements (which backstop the commercial paper program) include covenants and events of default typical for this type of facility, including a maximum debt/capital test and, for AEP and its significant subsidiaries, a $50 million cross-acceleration provision. At December 31, 2010, AEP was in compliance with its debt covenants. With the exception of a voluntary bankruptcy or insolvency, any event of default has either or both a cure period or notice requirement before termination of the agreements. A voluntary bankruptcy or insolvency of AEP or one of its significant subsidiaries would be considered an immediate termination event. See *Management's Financial Discussion and Analysis*, included in the 2010 Annual Reports, under the heading entitled *Financial Condition* for additional information with respect to AEP's credit agreements.

AEP's subsidiaries have also utilized, and expect to continue to utilize, additional financing arrangements, such as leasing arrangements, including the leasing of coal transportation equipment and facilities.

ENVIRONMENTAL AND OTHER MATTERS

General

AEP's subsidiaries are currently subject to regulation by federal, state and local authorities with regard to air and water-quality control and other environmental matters, and are subject to zoning and other regulation by local authorities. The environmental issues that we believe are potentially material to the AEP system are outlined below.

Clean Air Act Requirements

The CAA establishes a comprehensive program to protect and improve the nation's air quality and control mobile and stationary sources of air emissions. The major CAA programs affecting our power plants are described below. The states implement and administer many of these programs and could impose additional or more stringent requirements.

The Acid Rain Program: The 1990 Amendments to the CAA include a cap-and-trade emission reduction program for SO_2 emissions from power plants. By 2000, the program established a nationwide cap on power plant SO_2 emissions of 8.9 million tons per year. The 1990 Amendments also contain requirements for power plants to reduce NO_x emissions through the use of available combustion controls.

The success of the SO_2 cap-and-trade program encouraged the Federal EPA and the states to use it as a model for other emission reduction programs. We continue to meet our obligations under the Acid Rain Program through the installation of controls, use of alternate fuels and participation in the emissions allowance markets. Subsequent programs developed by Federal EPA have imposed more stringent SO_2 and NOx emission reduction requirements than the Acid Rain Program on many of our facilities. We have installed additional controls and taken other actions to achieve compliance with these programs.

National Ambient Air Quality Standards: The CAA requires the Federal EPA to review the available scientific data for criteria pollutants periodically and establish a concentration level in the ambient air for those substances that is adequate to protect the public health and welfare with an extra safety margin. Federal EPA also can list additional pollutants and develop concentration levels for them. These concentration levels are known as national ambient air quality standards (NAAQS).

Each state identifies the areas within its boundaries that meet the NAAQS (attainment areas) and those that do not (nonattainment areas). Each state must develop a state implementation plan (SIP) to bring nonattainment areas into compliance with the NAAQS and maintain good air quality in attainment areas. All SIPs are submitted to the Federal EPA for approval. If a state fails to develop adequate plans, the Federal EPA develops and implements a plan. As the Federal EPA reviews the NAAQS and establishes new concentration levels, the attainment status of areas can change and states may be required to develop new SIPs. In 2008, the Federal EPA issued revised NAAQS for both ozone and fine particulate matter ($PM_{2.5}$). The $PM_{2.5}$ standard was remanded by the D.C. Circuit Court of Appeals, and a new standard is under development. In 2009 the Obama Administration reconsidered the ozone standard and proposed a more stringent standard, which is expected to be finalized in 2011. Federal EPA has also adopted a new short-term standard for SO_2, a lower standard for NO_2, and a lower standard for lead. The states will develop new SIPs for these standards, which could result in additional emission reductions being required from our facilities.

In 2005, the Federal EPA issued the Clean Air Interstate Rule (CAIR), which requires additional reductions in SO_2 and NO_x emissions from power plants and assists states developing new SIPs to meet the NAAQS. For additional information regarding CAIR, see *Management's Financial Discussion and Analysis* under the headings entitled *Environmental Matters—Clean Air Act Requirements.* In July 2010, the Federal EPA issued a proposed rule to replace CAIR (the Transport Rule) that would impose new and more stringent requirements to control SO_2 and NO_x emissions from fossil fuel-fired electric generating units in 31 states and the District of Columbia. For additional information regarding the Transport Rule, see *Management's Financial Discussion and Analysis* under the headings entitled *Environmental Matters—Clean Air Act Requirements.*

Hazardous Air Pollutants: As a result of the 1990 Amendments to the CAA, the Federal EPA investigated hazardous air pollutant (HAP) emissions from the electric utility sector and submitted a report to Congress, identifying mercury emissions from coal-fired power plants as warranting further study. In 2005, the Federal EPA issued a Clean Air Mercury Rule (CAMR) setting New Source Performance Standards (NSPS) for mercury emissions from new and modified coal-fired power plants and requiring all states to issue new SIPs including mercury requirements for existing coal-fired power plants. For additional information regarding CAMR, see *Management's Financial Discussion and Analysis* under the headings entitled *Environmental Matters—Clean Air Act Requirements.*

Regional Haze: The CAA establishes visibility goals for certain federally designated areas, including national parks, and requires states to submit SIPs that will demonstrate reasonable progress toward preventing impairment of visibility in these areas (Regional Haze program). In 2005, the Federal EPA issued its Clean Air Visibility Rule (CAVR), detailing how the CAA's best available retrofit technology requirements will be applied to facilities built between 1962 and 1977 that emit more than 250 tons per year of certain pollutants in specific industrial categories, including power plants. For additional information regarding CAVR, see *Management's Financial Discussion and Analysis* under the headings entitled *Environmental Matters—Clean Air Act Requirements.*

In January 2009, the Federal EPA issued a determination that 37 states (including Indiana, Ohio, Oklahoma, Texas and Virginia) failed to submit SIP's fulfilling the Regional Haze program requirements by the deadline, and commencing a 2-year period for the development of a Federal Implementation Plan (FIP) in these states. Oklahoma subsequently submitted a proposed SIP to Federal EPA, but anticipates that Federal EPA will disapprove the plan and propose a FIP in early 2011. We are unable to predict if or how the remand of CAIR or the development of a FIP to satisfy CAVR in certain states may affect our compliance obligations for the Regional Haze programs.

Greenhouse Gas Emissions: In the absence of comprehensive climate change legislation, Federal EPA has taken action to regulate CO_2 emissions under the existing requirements of the CAA. Such actions are being legally challenged by numerous parties. For additional information regarding Federal EPA action taken to regulate CO_2 emissions, see *Management's Financial Discussion and Analysis* under the headings entitled *Environmental Matters—Clean Air Act Requirements.*

Our fossil fuel-fired generating units are large sources of CO_2 emissions. If substantial CO_2 emission reductions are required, there will be significant increases in capital expenditures and operating costs which would hasten the ultimate retirement of older, less-efficient, coal-fired units. To the extent we install additional controls on our generating plants to limit CO_2 emissions and receive regulatory approvals to increase our rates, return on capital investment would have a positive effect on future earnings. Prudently incurred capital investments made by our subsidiaries in rate-regulated jurisdictions to comply with legal requirements and benefit customers are generally included in rate base for recovery and earn a return on investment. We would expect these principles to apply to investments made to address new environmental requirements. However, requests for rate increases reflecting these costs can affect us adversely because our regulators could limit the amount or timing of increased costs that we would recover through higher rates. To the extent our costs are relatively higher than our competitors' costs, such as operators of nuclear generation, it could reduce our off-system sales or cause us to lose customers in jurisdictions that permit customers to choose their supplier of generation service.

Several states have adopted programs that directly regulate CO_2 emissions from power plants, but none of these programs are currently in effect in states where we have generating facilities. Certain states, including Ohio, Michigan, Texas and Virginia, passed legislation establishing renewable energy, alternative energy and/or energy efficiency requirements. We are taking steps to comply with these requirements.

Clean Water Act Requirements

Our operations are also subject to the Federal Clean Water Act, which prohibits the discharge of pollutants into waters of the United States except pursuant to appropriate permits, and regulates systems that withdraw surface water for use in our power plants. In 2004, the Federal EPA issued a final rule requiring all large existing power plants with once-through cooling water systems to meet certain standards to reduce mortality of aquatic organisms pinned against the plant's cooling water intake screen or entrained in the cooling water. The standards varied based on the water bodies from which the plants draw their cooling water.

In July 2007, the Federal EPA suspended the 2004 rule, except for the requirement that permitting agencies develop best professional judgment (BPJ) controls for existing facility cooling water intake structures that reflect the best technology available for minimizing adverse environmental impact. The result is that the BPJ control standard for cooling water intake structures in effect prior to the 2004 rule is used as the applicable standard by permitting agencies pending finalization of revised rules by the Federal EPA.

In April 2009, the U.S. Supreme Court issued a decision that allows the Federal EPA the discretion to rely on cost-benefit analysis in setting national performance standards and in providing for cost-benefit variances from those standards as part of the regulations. We cannot predict if or how the Federal EPA will apply this decision to any revision of the regulations or what effect it may have on similar requirements adopted by the states. We expect Federal EPA to issue revised rules in 2011.

Federal EPA is also engaged in rulemaking to update the technology-based standards that govern discharges from new and existing power plants under the Clean Water Act's NPDES program. These standards were last updated over 20 years ago, and EPA has issued two rounds of information collection requests to inform its rulemaking. In October 2009, Federal EPA issued a final report for the power plant sector and determined that revisions to its existing standards are necessary, but EPA has not yet proposed any specific requirements. Until new standards are proposed, we cannot predict the outcome or impact of these rules on our operations.

Coal Ash Regulation

Our operations produce a number of different coal combustion products, including flyash, bottom ash, gypsum, and other materials. In December 2008, the breach of a dike at the Tennessee Valley Authority's Kingston Station resulted in a spill of several million cubic yards of ash into a nearby river and onto private properties, prompting federal and state reviews of ash storage and disposal practices at many coal-fired electric generating facilities, including ours. AEP operates 37 ash ponds and we manage these ponds in a manner that complies with state and local requirements, including dam safety rules designed to assure the structural integrity of these facilities. We also operate a number of dry disposal facilities in accordance with state standards, including ground water monitoring and other applicable standards. Federal EPA completed an extensive study of the characteristics of coal ash in 2000 and concluded that combustion wastes do not warrant regulation as hazardous waste.

In June 2010, the Federal EPA published a proposed rule to regulate the disposal and beneficial re-use of coal combustion residuals, including fly ash and bottom ash generated at coal-fired electric generating units. For additional information regarding Federal EPA action taken to regulate the disposal and beneficial re-use of coal combustion residuals and the potential impact on our operations., see *Management's Financial Discussion and Analysis* under the headings entitled *Environmental Matters—Coal Combustion Residual Rule.*

Global Warming

Position and strategy: We continue to support a federal legislative approach to energy policy as the most effective means of reducing emissions of CO_2 and other greenhouse gases (generally referred to as CO_2) that recognizes that a reliable and affordable electricity supply is vital to economic recovery and growth. We do not believe regulating CO_2 emissions under the Clean Air Act is the appropriate solution. During the past decade, we have taken voluntary actions to reduce and offset our CO_2 emissions. Unfortunately, two of the voluntary programs that helped businesses such as AEP to set quantitative commitments no longer exist. The U.S. EPA's Climate Leaders Program and the Chicago Climate Exchange both ended their reduction obligations at the end of 2010. However, through these programs and others, we voluntarily reduced our CO_2 emissions by approximately 94 million metric tons during the 2003 to 2009 period. We expect our emissions to continue to decline over time as we diversify our generating sources and operate fewer coal units. The projected decline in coal-fired generation is due to a number of factors including the ongoing cost of operating older units, increasing environmental regulations requiring significant capital investments and changing commodity market fundamentals. Our strategy for this transformation is to protect the reliability of the electric system and reduce our emissions by pursuing multiple options. These include diversifying our fuel portfolio and generating more electricity from natural gas, supporting incentives to invest in more nuclear generation, carbon capture and storage and other advanced coal technologies, increasing energy efficiency and investing in renewable resources, where there is regulatory support. Meanwhile the U.S. EPA began regulating CO_2 emissions from large stationary sources such as power plants in 2011 by issuing a series of rules under the NSR prevention of significant deterioration and Title V operating permit programs in the states.

For additional information on legislative and regulatory responses to global warming, including limitations on CO_2 emissions, see *Management's Financial Discussion and Analysis* under the headings entitled *Environmental Matters – Global Warming*. Specific steps taken to reduce CO_2 emissions include the following:

Carbon Capture and Storage

The 20 MW CCS Validation Project at the Mountaineer Plant in West Virginia successfully captured over 27,000 metric tons of CO_2 between 2009 and 2010 and stored over 17,000 metric tons underground. In January 2011, we began preliminary engineering and design work for a second, commercial-scale coal-derived CO_2 capture and storage system at the Mountaineer Plant. We are also updating our estimates for the costs related to the commercial scale project. We will evaluate the updated estimates before any decision is made to seek the necessary regulatory approvals to build the commercial scale project. The project will be partially funded through the U.S. Department of Energy's Clean Coal Power Initiative. AEP was awarded federal grant funding of $334 million, which represents approximately half the expected cost of this project, exclusive of asset retirement obligations.

Renewable Sources of Energy

Some of our states have laws or commission orders that establish requirements or goals for renewable and/or alternative energy (Louisiana, Ohio, Arkansas, Michigan, West Virginia, Texas, Virginia and Oklahoma) and we are taking steps to comply with these rules in a timely fashion. A key sustainability commitment we made is to increase renewable power by an additional 2,000 MW from 2007 levels by 2011, subject to regulatory approval. By the end of 2010, AEP secured through power purchase agreements an additional 1,111 MW of renewable power.

End User Energy Efficiency

Energy efficiency is a high priority for AEP because it can be a cost-effective way to reduce energy demand and potentially delay the need for new power plants. We work collaboratively with regulators, technical experts, environmental groups and others to develop and implement efficiency and demand response programs. From 2008 through 2010, we have achieved approximately 321 MW and 1,072,000 MWh of demand and energy reductions, respectively. We have a company 2012 goal to reduce 1,000 MW of demand and 2,250,000 MWh of energy consumption. We expect to surpass our energy reduction target subject to regulatory approvals, appropriate cost recovery, and continued customer demand for programs. In 2010, we invested over $70 million throughout most of our service territory in energy efficiency initiatives.

gridSMART®

AEP's *gridSMART®* initiative is designed to demonstrate the potential benefits of the smart grid by integrating advanced grid technologies into existing electric networks. AEP is deploying smart grid technologies in several jurisdictions with regulatory support.

- AEP Ohio is deploying a comprehensive suite of smart grid technologies in an innovative demonstration project with 110,000 customers. The $150 million project is being funded through a $75 million federal grant, PUCO cost recovery support, and vendor in-kind contributions.

- AEP Texas is deploying a 970,000 meter smart grid network, along with $1 million in energy use display devices for low income customers. The $308 million project is targeted for completion by the end of 2013. We are recovering the costs through an 11-year surcharge.

- I&M has deployed a smart grid network to 10,000 customers. The $7 million project is initially being funded pursuant to a settlement agreement approved by the IURC. Ongoing expenses will be considered in future rate cases.

- With partial cost recovery support from the OCC, PSO is deploying a 15,000 smart meter network.

Current and Projected CO_2 Emissions: Our total CO_2 emissions in 2009 (including our ownership in the Kyger Creek and Clifty Creek plants) were approximately 136 million metric tons. We estimate that our 2010 emissions were approximately 140 million metric tons. Emissions in 2011 and beyond will be affected by continued changes in our generation portfolio, market prices, the pace and scale of the economic recovery in our jurisdictions, available capital, weather, and other factors. We expect overall increases in CO_2 emissions during the next few years to be small, if at all realized, as our sales and generation rebound somewhat from recession lows in 2009. However, over much of the remainder of the decade we expect emissions to decline as modest sales growth is offset by retirements of older, less efficient coal-fired units and increased utilization of natural gas.

Corporate Governance: In response to a shareholder proposal several years ago, our Board of Directors created an ad hoc committee to evaluate our actions to mitigate the economic impact from future policies to reduce CO_2 and other emissions. Our Board of Directors continually reviews the risks posed by and our actions in response to environmental issues and in connection with its assessment of our strategic plan. The Board of Directors is frequently informed of any new material environmental issues, including changes to regulations and proposed legislation. The Board's Committee on Directors and Corporate Governance oversees the company's annual Corporate Accountability Report, which includes information on environmental issues. Environmental planning and policy leadership are criteria incorporated into our executive compensation plan.

Other environmental issues and matters

- Litigation with the federal and/or certain state governments and certain special interest groups regarding regulated air emissions and/or whether emissions from coal-fired generating plants cause or contribute to global warming. See *Management's Financial Discussion and Analysis* under the heading entitled *Litigation - Environmental Litigation* and Note 6 to the consolidated financial statements entitled *Commitments, Guarantees and Contingencies*, included in the 2010 Annual Reports, for further information.

- CERCLA, which imposes costs for environmental remediation upon owners and previous owners of sites, as well as transporters and generators of hazardous material disposed of at such sites. See Note 6 to the consolidated financial statements entitled *Commitments, Guarantees and Contingencies*, included in the 2010 Annual Reports, under the heading entitled *The Comprehensive Environmental Response Compensation and Liability Act (Superfund) and State Remediation* for further information.

Environmental Investments

Investments related to improving AEP System plants' environmental performance and compliance with air and water quality standards during 2008, 2009 and 2010 and the current estimates for 2011, 2012 and 2013 are shown below, in each case excluding AFUDC or capitalized interest. Estimated construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, and the ability to access capital. AEP expects to make substantial investments in future years in addition to the amounts set forth below in connection with the modification and addition of facilities at generating plants for environmental quality controls. Such future investments are needed in order to comply with air and water quality standards that have been adopted and have deadlines for compliance after 2011 or have been proposed and may be adopted. Future investments could be significantly greater if emissions reduction requirements are accelerated or otherwise become more onerous or if CO_2 becomes regulated. While we expect to recover our expenditures for pollution control technologies, replacement generation and associated operating costs from customers through regulated rates (in regulated jurisdictions) or market prices, without such recovery those costs could adversely affect future results of operations and cash flows, and possibly financial condition. The cost of complying with applicable environmental laws, regulations and rules is expected to be material to the AEP System. See *Management's Financial Discussion and Analysis* under the heading entitled *Environmental Matters* and Note 6 to the consolidated financial statements, entitled *Commitments, Guarantees and Contingencies,* included in the 2010 Annual Reports, for more information regarding environmental expenditures in general.

Historical and Projected Environmental Investments

	2008 Actual	2009 Actual	2010 Actual	2011 Estimate	2012 Estimate	2013 Estimate
			(in thousands)			
Total AEP System*	$886,800	$457,200	$303,800	$223,100	$340,300	$678,500
APCo	361,200	191,900	202,700	112,100	125,700	182,500
CSPCo	162,800	73,800	52,100	20,700	18,800	28,000
I&M	22,400	19,600	8,100	1,500	700	4,400
OPCo	311,800	151,000	45,300	50,300	69,000	193,700
PSO	5,000	1,000	1,200	7,400	6,100	5,100
SWEPCo**	12,000	10,700	(10,500)	10,300	28,000	89,200

* Includes expenditures of the subsidiaries shown and other subsidiaries not shown. The figures reflect construction expenditures, not investments in subsidiary companies. Excludes discontinued operations.

** SWEPCo 2010 actual environmental cost includes reclassifications of project costs for suspended capital projects.

Electric and Magnetic Fields

EMF are found everywhere there is electricity. Electric fields are created by the presence of electric charges. Magnetic fields are produced by the flow of those charges. This means that EMF are created by electricity flowing in transmission and distribution lines, electrical equipment, household wiring, and appliances. A number of studies in the past have examined the possibility of adverse health effects from EMF. While some of the epidemiological studies have indicated some association between exposure to EMF and health effects, none has produced any conclusive evidence that EMF does or does not cause adverse health effects.

Management cannot predict the ultimate impact of the question of EMF exposure and adverse health effects. If further research shows that EMF exposure contributes to increased risk of cancer or other health problems, or if the courts conclude that EMF exposure harms individuals and that utilities are liable for damages, or if states limit the strength of magnetic fields to such a level that the current electricity delivery system must be significantly changed, then the results of operations and financial condition of AEP and its operating subsidiaries could be materially adversely affected unless these costs can be recovered from customers.

UTILITY OPERATIONS

GENERAL

Utility operations constitute most of AEP's business operations. Utility operations include (i) the generation, transmission and distribution of electric power to retail customers and (ii) the supplying and marketing of electric power at wholesale (through the electric generation function) to other electric utility companies, municipalities and other market participants. AEPSC, as agent for AEP's public utility subsidiaries, performs marketing, generation dispatch, fuel procurement and power-related risk management and trading activities.

ELECTRIC GENERATION

Facilities

AEP's public utility subsidiaries own or lease approximately 37,000 MW of domestic generation. See *Item 2 — Properties* for more information regarding AEP's generation capacity.

AEP Power Pool

APCo, CSPCo, I&M, KPCo, OPCo, and AEPSC are parties to the Interconnection Agreement, which was originally approved by the FERC in 1951 and subsequently amended in 1951, 1962, 1975, 1979 (twice) and 1980. This agreement defines how the member companies share the costs and benefits associated with their generating plants. This sharing is based upon each company's "member load ratio." The member load ratio is calculated monthly by dividing each company's highest monthly peak demand for the last twelve months by the aggregate of the highest monthly peak demand for the last twelve months for all member companies. The member load ratio multiplied by the aggregate generation capacity of all the member companies determines each member company's capacity obligation. The difference between each member company's obligation and its own generation capacity determines the capacity surplus or deficit of each member company. The agreement requires the deficit companies to make monthly capacity equalization payments to the surplus companies based on the surplus companies' average fixed cost of generation. Member companies that deliver energy to other member companies to meet their internal load requirements are reimbursed at average variable costs. In addition, all member companies share off-system sales margins based upon each member company's member load ratio. Consequently, the agreement provides a strong risk sharing and mitigation arrangement among the member companies. As of December 31, 2010, the member-load-ratios were as follows:

	Peak Demand (MW)	Member-Load Ratio (%)
APCo	7,623	32.8
CSPCo	4,289	18.5
I&M	4,474	19.3
KPCo	1,596	6.9
OPCo	5,235	22.5

APCo, CSPCo, I&M, KPCo and OPCo are parties to the AEP System Interim Allowance Agreement (Allowance Agreement), which has been approved by the FERC and provides, among other things, for the transfer of SO_2 emission allowances associated with transactions under the Interconnection Agreement. The following table shows the net (credits) or charges allocated among the parties under the Interconnection Agreement during the years ended December 31, 2008, 2009 and 2010:

	2008	2009	2010
		(in thousands)	
APCo	$575,300	$668,700	$757,900
CSPCo	233,200	257,600	230,400
I&M	(153,000)	(100,900)	(236,900)
KPCo	65,000	31,600	49,400
OPCo	(720,500)	(857,000)	(800,800)

Notification of Termination of the Power Pool

Much has changed since the Interconnection Agreement was originally executed in 1951. These changes include evolving environmental regulations; the introduction of "open access" to transmission facilities; the implementation of RTOs, including PJM, which is a robust generation power pool that has generating capacity of over 167,000 MWs, movement towards industry deregulation; increased competition in wholesale generation markets; and the effects of these changes on such things as costs, load and the array of supply and demand-side resources available to the AEP-East operating companies today.

Consequently, in December 2010, each Power Pool member gave written notice to the other members, and AEPSC, the Pool's agent, of its decision to terminate the Interconnection Agreement, effective January 1, 2014 or such other date as approved by FERC, subject to state regulatory input. This decision to terminate is subject to ongoing evaluation by AEP. Because the Interconnection Agreement is a rate schedule on file at FERC, its termination will not be effective until accepted for filing by FERC. The Interim Allowance Agreement would also be terminated on the same date.

By giving notice to terminate the Interconnection Agreement and the Interim Allowance Agreement, the Power Pool members are providing a timeline within which all Power Pool members will decide how they will respond to the impacts from modifying or terminating the Interconnection Agreement. The result of this process might be a modified or different type of Pool. Final resolution could involve bilateral contracts or sales of generating assets from surplus members to deficit members. If the Power Pool members do not reach a consensus, the Power Pool members could revoke their notices of termination and the Interconnection Agreement would remain in place.

CSW Operating Agreement

PSO, SWEPCo and AEPSC are parties to the CSW Operating Agreement, which has been approved by the FERC. The CSW Operating Agreement requires these public utility subsidiaries to maintain adequate annual planning reserve margins and requires the subsidiaries that have capacity in excess of the required margins to make such capacity available for sale to other public utility subsidiary parties as capacity commitments. Parties are compensated for energy delivered to the recipients based upon the deliverer's incremental cost plus a portion of the recipient's savings realized by the purchaser that avoids the use of more costly alternatives. Revenues and costs arising from third party sales in their region are generally shared based on the amount of energy each west zone public utility subsidiary contributes that is sold to third parties.

The following table shows the net (credits) or charges allocated among the parties under the CSW Operating Agreement during the years ended December 31, 2008, 2009 and 2010:

	2008	2009	2010
		(in thousands)	
PSO	$(57,000)	$(22,762)	$20,222
SWEPCo	59,900	22,762	(20,222)

Power generated by or allocated or provided under the Interconnection Agreement or CSW Operating Agreement to any public utility subsidiary is primarily sold to customers by such public utility subsidiary at rates approved by the public utility commission in the jurisdiction of sale. See *Regulation — Rates* under *Item 1, Utility Operations.*

Under both the Interconnection Agreement and CSW Operating Agreement, power that is not needed to serve the native load of our public utility subsidiaries is sold in the wholesale market by AEPSC on behalf of those subsidiaries. See *Risk Management and Trading*, below, for a discussion of the trading and marketing of such power.

AEP's System Integration Agreement provides for the integration and coordination of AEP's East companies, PSO and SWEPCo. This includes joint dispatch of generation within the AEP System and the distribution, between the two zones, of costs and benefits associated with the transfers of power between the two zones (including sales to third parties and risk management and trading activities). It is designed to function as an umbrella agreement in addition to the Interconnection Agreement and the CSW Operating Agreement, each of which controls the distribution of costs and benefits for activities within each zone.

Risk Management and Trading

As agent for AEP's public utility subsidiaries, AEPSC sells excess power into the market and engages in power, natural gas, coal and emissions allowances risk management and trading activities focused in regions in which AEP traditionally operates and in adjacent regions. These activities primarily involve the purchase and sale of electricity (and to a lesser extent, natural gas, coal and emissions allowances) under physical forward contracts at fixed and variable prices. These contracts include physical transactions, over-the-counter swaps and exchange-traded futures and options. The majority of physical forward contracts are typically settled by netting into offsetting contracts. These transactions are executed with numerous counterparties or on exchanges. Counterparties and exchanges may require cash or cash related instruments to be deposited on these transactions as margin against open positions. As of December 31, 2010, counterparties have posted approximately $28 million in cash, cash equivalents or letters of credit with AEPSC for the benefit of AEP's public utility subsidiaries (while, as of that date, AEP's public utility subsidiaries had posted approximately $172 million with counterparties and exchanges). Since open trading contracts are valued based on market prices of various commodities, exposures change daily. See *Management's Financial Discussion and Analysis*, included in the 2010 Annual Reports, under the heading entitled *Quantitative and Qualitative Disclosures About Risk Management Activities* for additional information.

Fuel Supply

The following table shows the sources of fuel used by the AEP System:

	2008	2009	2010
Coal and Lignite	86%	88%	82%
Natural Gas	6%	6%	8%
Nuclear	8%	5%	9%
Hydroelectric and other	<1%	1%	<1%

Price increases in one or more fuel sources relative to other fuels may result in increased use of other fuels. Variations in the generation of nuclear power are primarily related to a 2008 forced outage caused by a low pressure turbine blade failure event. The unit returned to service in December 2009.

Coal and Lignite: AEP's public utility subsidiaries procure coal and lignite under a combination of purchasing arrangements including long-term contracts, affiliate operations and spot agreements with various producers and coal trading firms. Electric demand experienced a slight increase in 2010 which resulted in a slight increase in coal and lignite tons consumed. In response to continued lower consumption rates at certain locations during 2010, AEP continued to work with coal suppliers to better match deliveries with consumption and minimize the impact on fuel inventory costs, carrying costs and cash. System wide, inventory levels were reduced by 11 days in 2010.

Management believes that AEP's public utility subsidiaries will be able to secure and transport coal and lignite of adequate quality and in adequate quantities to operate their coal and lignite-fired units. Through subsidiaries, AEP owns, leases or controls more than 8,100 railcars, 672 barges, 17 towboats and a coal handling terminal with 18 million tons of annual capacity to move and store coal for use in our generating facilities. See AEP River Operations for a discussion of AEP's for-profit coal and other dry-bulk commodity transportation operations that are not part of AEP's Utility Operations segment.

During 2010, spot market prices for coal generally increased throughout the year. Among other things, these increases are due to higher international demand for U.S. coals, and increased mining costs related to regulatory and permitting issues. Most of the coal purchased by AEP is procured through term contracts. The price we pay under a number of these contracts is often lower than the spot market price for similar coal. As term contracts expire they are replaced with new agreements, often at higher prices. The price we paid for coal delivered in 2010 decreased from the prior year, due in part to the expiration of several high spot market contracts that were entered into in 2007 and 2008 for 2009 and the reopening of some contracts to current market prices.

The following table shows the amount of coal and lignite delivered to the AEP System plants during the past three years and the average delivered price of coal purchased by AEP System companies:

	2008	**2009**	**2010**
Total coal delivered to AEP System plants (thousands of tons)	77,054	75,909	64,614
Average price per ton of purchased coal	\$47.14	\$49.54	\$44.82

The coal supplies at AEP System plants vary from time to time depending on various factors, including, but not limited to, demand for electric power, unit outages, transportation infrastructure limitations, space limitations, plant coal consumption rates, availability of acceptable coals, labor issues and weather conditions which may interrupt production or deliveries. At December 31, 2010, the System's coal inventory was approximately 50 days of full load burn.

In cases of emergency or shortage, AEP has developed programs to conserve coal supplies at its plants. Such programs have been filed and reviewed with federally approved electric reliability organizations. In some cases, the relevant state regulatory agency has prescribed actions to be taken under specified circumstances by System companies, subject to the jurisdiction of such agency.

The FERC has adopted regulations relating, among other things, to the circumstances under which, in the event of fuel emergencies or shortages, it might order electric utilities to generate and transmit electric power to other regions or systems experiencing fuel shortages, and to ratemaking principles by which such electric utilities would be compensated. In addition, the federal government is authorized, under prescribed conditions, to reallocate coal and to require the transportation thereof, for the use at power plants or major fuel-burning installations experiencing fuel shortages.

Natural Gas: Through its public utility subsidiaries, AEP consumed nearly 134 billion cubic feet of natural gas during 2010 for generating power. This represents a significant increase from 2009 due to lower natural gas prices and the addition of the 508 MW combined-cycle unit at SWEPCO's J. Lamar Stall facility and the overall increased natural gas demand throughout AEP's system. Many of the natural gas-fired power plants are connected to at least two pipelines, which allows greater access to competitive supplies and improves delivery reliability. A portfolio of long-term, monthly, seasonal firm and daily peaking purchase and transportation agreements (that are entered into on a competitive basis and based on market prices) supplies natural gas requirements for each plant, as appropriate.

Nuclear: I&M has made commitments to meet the current nuclear fuel requirements of the Cook Plant. I&M has made and will make purchases of uranium in various forms in the spot, short-term, and mid-term markets. I&M also continues to lease a portion of its nuclear fuel requirements.

For purposes of the storage of high-level radioactive waste in the form of spent nuclear fuel, I&M completed modifications to its spent nuclear fuel storage pool more than 10 years ago. I&M anticipates that the Cook Plant has sufficient storage capacity for its spent nuclear fuel to permit normal operations through 2013. I&M has entered into an agreement to provide for onsite dry cask storage. Initial loading of spent nuclear fuel into the dry casks is tentatively scheduled to begin in 2012.

Nuclear Waste and Decommissioning

As the owner of the Cook Plant, I&M has a significant future financial commitment to dispose of spent nuclear fuel and decommission and decontaminate the plant safely. The cost to decommission a nuclear plant is affected by NRC regulations and the spent nuclear fuel disposal program. In 2009, when the most recent study was done, the estimated cost of decommissioning and disposal of low-level radioactive waste for the Cook Plant ranged from $831 million to $1.5 billion in 2009 non-discounted dollars. At December 31, 2010, the total decommissioning trust fund balance for the Cook Plant was approximately $1.2 billion. The balance of funds available to decommission Cook Plant will differ based on contributions and investment returns. The ultimate cost of retiring the Cook Plant may be materially different from estimates and funding targets as a result of the:

- Type of decommissioning plan selected;
- Escalation of various cost elements (including, but not limited to, general inflation and the cost of energy);
- Further development of regulatory requirements governing decommissioning;
- Technology available at the time of decommissioning differing significantly from that assumed in studies;
- Availability of nuclear waste disposal facilities; and
- Availability of a DOE facility for permanent storage of spent nuclear fuel.

Accordingly, management is unable to provide assurance that the ultimate cost of decommissioning the Cook Plant will not be significantly different than current projections. We will seek recovery from customers through our regulated rates if actual decommissioning costs exceed our projections. See Note 6 to the consolidated financial statements, entitled *Commitments, Guarantees and Contingencies* under the heading *Nuclear Contingencies*, included in the 2010 Annual Reports, for information with respect to nuclear waste and decommissioning.

Low-Level Radioactive Waste: The LLWPA mandates that the responsibility for the disposal of low-level radioactive waste rests with the individual states. Low-level radioactive waste consists largely of ordinary refuse and other items that have come in contact with radioactive materials. Michigan does not currently have a disposal site for such waste available. I&M cannot predict when such a site may be available, but Utah licenses a low-level radioactive waste disposal site which currently accepts low-level radioactive waste from Michigan. I&M ships some of its low level waste to a facility in Utah. There is currently no set date limiting I&M's access to the Utah facility. I&M stores the remaining type of low-level waste onsite. In order to have capacity for the duration of its licensed operation of Cook Plant for onsite storage of waste not shipped to Utah, I&M will have to modify its existing facilities sometime in the next ten to fifteen years.

Structured Arrangements Involving Capacity, Energy, and Ancillary Services

In January 2000, OPCo and NPC, an affiliate of Buckeye, entered into an agreement relating to the construction and operation of a 510 MW gas-fired electric generating peaking facility to be owned by NPC, called the Mone Plant. OPCo is entitled to 100% of the power generated by the Mone Plant, and is responsible for the fuel and other costs of the facility through May 2012, as extended. Following that, NPC and OPCo will be entitled to 80% and 20%, respectively, of the power of the Mone Plant, and both parties will generally be responsible for their allocable portion of the fuel and other costs of the facility.

Certain Power Agreements

I&M: The Unit Power Agreement between AEGCo and I&M, dated March 31, 1982, provides for the sale by AEGCo to I&M of all the capacity (and the energy associated therewith) available to AEGCo at the Rockport Plant. Whether or not power is available from AEGCo, I&M is obligated to pay a demand charge for the right to receive such power (and an energy charge for any associated energy taken by I&M). The agreement will continue in effect until the last of the lease terms of Unit 2 of the Rockport Plant has expired (currently December 2022) unless extended in specified circumstances.

Pursuant to an assignment between I&M and KPCo, and a unit power agreement between KPCo and AEGCo, AEGCo sells KPCo 30% of the capacity (and the energy associated therewith) available to AEGCo from both units of the Rockport Plant. KPCo has agreed to pay to AEGCo the amounts that I&M would have paid AEGCo under the terms of the Unit Power Agreement between AEGCo and I&M for such entitlement. The KPCo unit power agreement expires in December 2022.

CSPCo: The Unit Power Agreement between AEGCo and CSPCo, dated March 15, 2007, provides for the sale by AEGCo to CSPCo of all the capacity and associated unit contingent energy and ancillary services available to AEGCo at the Lawrenceburg Plant that are scheduled and dispatched by CSPCo. CSPCo is obligated to pay a capacity charge (whether or not power is available from the Lawrenceburg Plant), and the fuel, operating and maintenance charges associated with the energy dispatched by CSPCo, and to reimburse AEGCo for other costs associated with the operation and ownership of the Lawrenceburg Plant. The agreement will continue in effect until December 31, 2017 unless extended as set forth in the agreement.

OVEC: AEP and several unaffiliated utility companies jointly own OVEC. The aggregate equity participation of AEP in OVEC is 43.47%. Until 2001, OVEC supplied from its generating capacity the power requirements of a uranium enrichment plant near Portsmouth, Ohio owned by the DOE. The sponsoring companies are entitled to receive and are obligated to pay for all OVEC capacity (approximately 2,200 MW) in proportion to their respective power participation ratios. The aggregate power participation ratio of APCo, CSPCo, I&M and OPCo is 43.47%. The proceeds from the sale of power by OVEC are designed to be sufficient for OVEC to meet its operating expenses and fixed costs and to provide a return on its equity capital. The Inter-Company Power Agreement, which defines the rights of the owners and sets the power participation ratio of each, will expire by its terms in March 2026. Negotiations are in process among the owners to extend this agreement until 2040. AEP and the other owners have authorized environmental investments related to their ownership interests. As of December 2010, OVEC's Board of Directors has authorized capital expenditures totaling approximately $1.35 billion in connection with the engineering and construction of flue gas desulfurization projects and the associated scrubber waste disposal landfills at its two generating plants. OVEC has completed the financing of approximately $950 million for these projects through debt issuances and would expect to finance the remaining cost by issuing additional debt.

ELECTRIC TRANSMISSION AND DISTRIBUTION

General

AEP's public utility subsidiaries (other than AEGCo) own and operate transmission and distribution lines and other facilities to deliver electric power. See *Item 2—Properties* for more information regarding the transmission and distribution lines. Most of the transmission and distribution services are sold, in combination with electric power, to retail customers of AEP's public utility subsidiaries in their service territories. These sales are made at rates approved by the state utility commissions of the states in which they operate, and in some instances, approved by the FERC. See *Item 1 –Utility Operations - Regulation—Rates.* The FERC regulates and approves the rates for wholesale transmission transactions. See *Item 1 –Utility Operations - Regulation—FERC.* As discussed below, some transmission services also are separately sold to non-affiliated companies.

AEP's public utility subsidiaries (other than AEGCo) hold franchises or other rights to provide electric service in various municipalities and regions in their service areas. In some cases, these franchises provide the utility with the exclusive right to provide electric service. These franchises have varying provisions and expiration dates. In general, the operating companies consider their franchises to be adequate for the conduct of their business. For a discussion of competition in the sale of power, see *Item 1 –Utility Operations - Competition*.

AEP Transmission Pool

Transmission Agreement: APCo, CSPCo, I&M, KPCo and OPCo operate their transmission lines as a single interconnected and coordinated system in the AEP East transmission zone and are parties to the Transmission Agreement (TA), defining how they share the costs and benefits associated with their relative ownership of the bulk transmission system (lines operated at 138kV and above and stations containing extra high voltage equipment). The TA has been approved by the FERC. Sharing under the TA is based upon each company's "member-load-ratio." The member-load-ratio is calculated monthly by dividing such company's highest monthly peak demand for the last twelve months by the aggregate of the highest monthly peak demand for the last twelve months for all east zone operating companies. The respective peak demands and member-load-ratios as of December 31, 2010 are set forth above in the section titled *ELECTRIC GENERATION* – AEP Power Pool and CSW Operating Agreement.

In October 2010, the FERC approved our request to amend the TA effective November 1, 2010. KgPCo and WPCo were added as parties to the TA. In addition, the amendments generally provide for the allocation of PJM transmission costs on the basis of the TA parties' 12-month coincident peak and reimburse transmission revenues based on individual cost of service instead of the member-load ratio method previously used.

The following table shows the net (credits) or charges allocated among the parties to the TA during the years ended December 31, 2008, 2009 and 2010:

	2008	**2009**	**2010**
		(in thousands)	
APCo	$(29,000)	$(12,500)	$(16,000)
CSPCo	55,000	51,300	42,500
I&M	(37,000)	(38,400)	(25,200)
KPCo	(2,000)	(8,800)	(8,000)
OPCo	13,000	8,400	6,700

Transmission Coordination Agreement, OATT, and ERCOT Protocols: PSO, SWEPCo, TNC and AEPSC are parties to the TCA. Under the TCA, a coordinating committee is charged with the responsibility of (i) overseeing the coordinated planning of the transmission facilities of the parties to the agreement, including the performance of transmission planning studies, (ii) the interaction of such subsidiaries with independent system operators and other regional bodies interested in transmission planning and (iii) compliance with the terms of the OATT filed with the FERC and the rules of the FERC relating to such tariff. Pursuant to the TCA, AEPSC has responsibility for monitoring the reliability of their transmission systems and administering the OATT on behalf of the other parties to the agreement. The TCA also provides for the allocation among the parties of revenues collected for transmission and ancillary services provided under the OATT. These allocations have been determined by the FERC-approved OATT for the SPP (with respect to PSO and SWEPCo) and PUCT-approved protocols for ERCOT (with respect to TCC and TNC).

The following table shows the net (credits) or charges allocated pursuant to the TCA, SPP OATT and ERCOT protocols as described above during the years ended December 31, 2008, 2009 and 2010:

	2008	**2009**	**2010**
		(in thousands)	
PSO	$8,200	$11,000	$10,500
SWEPCo	(8,200)	(11,000)	(10,500)
TCC	1,500	1,700	2,100
TNC	(1,500)	(1,700)	(2,100)

Transmission Services for Non-Affiliates: In addition to providing transmission services in connection with their own power sales, AEP's public utility subsidiaries through RTOs also provide transmission services for non-affiliated companies. See *Item 1 –Utility Operations – Electric Transmission and Distribution - Regional Transmission Organizations,* below. Transmission of electric power by AEP's public utility subsidiaries is regulated by the FERC.

Coordination of East and West Zone Transmission: AEP's System Transmission Integration Agreement provides for the integration and coordination of the planning, operation and maintenance of the transmission facilities of AEP East and AEP West companies. The System Transmission Integration Agreement functions as an umbrella agreement in addition to the TA and the TCA. The System Transmission Integration Agreement contains two service schedules that govern:

- The allocation of transmission costs and revenues and
- The allocation of third-party transmission costs and revenues and System dispatch costs.

The System Transmission Integration Agreement contemplates that additional service schedules may be added as circumstances warrant.

Regional Transmission Organizations

The AEP East Companies are members of PJM, and SWEPCo and PSO are members of the SPP (both FERC-approved RTOs). RTOs operate, plan and control utility transmission assets in a manner designed to provide open access to such assets in a way that prevents discrimination between participants owning transmission assets and those that do not. The remaining AEP West companies (TCC and TNC) are members of ERCOT. See Note 4 to the consolidated financial statements, entitled *Rate Matters*, included in the 2010 Annual Reports under the heading entitled *Regional Transmission Rate Proceedings at the FERC* for additional information regarding RTOs.

REGULATION

General

Except for transmission and/or retail generation sales in certain of its jurisdictions, AEP's public utility subsidiaries' retail rates and certain other matters are subject to traditional cost-based regulation by the state utility commissions. AEP's subsidiaries are also subject to regulation by the FERC under the FPA with respect to wholesale power and transmission service transactions as well as certain unbundled retail transmission rates mainly in Ohio. I&M is subject to regulation by the NRC under the Atomic Energy Act of 1954, as amended, with respect to the operation of the Cook Plant. AEP and its public utility subsidiaries are also subject to the regulatory provisions of EPACT, much of which is administered by the FERC. EPACT provides the FERC limited "backstop" transmission siting authority as well as increased utility merger oversight.

Rates

Historically, state utility commissions have established electric service rates on a cost-of-service basis, which is designed to allow a utility an opportunity to recover its cost of providing service and to earn a reasonable return on its investment used in providing that service. A utility's cost of service generally reflects its operating expenses, including operation and maintenance expense, depreciation expense and taxes. State utility commissions periodically adjust rates pursuant to a review of (i) a utility's adjusted revenues and expenses during a defined test period and (ii) such utility's level of investment. Absent a legal limitation, such as a law limiting the frequency of rate changes or capping rates for a period of time, a state utility commission can review and change rates on its own initiative. Some states may initiate reviews at the request of a utility, customer, governmental or other representative of a group of customers. Such parties may, however, agree with one another not to request reviews of or changes to rates for a specified period of time.

Public utilities have traditionally financed capital investments until the new asset was placed in service. Provided the asset was found to be a prudent investment, it was then added to rate base and entitled to a return through rate recovery. Given long lead times in construction, the high costs of plant and equipment and difficult capital markets, we are actively pursuing strategies to accelerate rate recognition of investments and cash flow. AEP representatives continue to engage our state commissioners and legislators on alternative ratemaking options to reduce regulatory lag and enhance certainty in the process. These options include pre-approvals, a return on construction work in progress, rider/trackers, securitization, formula rates and the inclusion of future test-year projections into rates.

In many jurisdictions, the rates of AEP's public utility subsidiaries are generally based on the cost of providing traditional bundled electric service (i.e., generation, transmission and distribution service). In the ERCOT area of Texas, our utilities have exited the generation business and they currently charge unbundled cost-based rates for transmission and distribution service only. In Ohio, rates for electric service are unbundled for generation, transmission and distribution service. Historically, the state regulatory frameworks in the service area of the AEP System reflected specified fuel costs as part of bundled (or, more recently, unbundled) rates or incorporated fuel adjustment clauses in a utility's rates and tariffs. Fuel adjustment clauses permit periodic adjustments to fuel cost recovery from customers and therefore provide protection against exposure to fuel cost changes.

The following state-by-state analysis summarizes the regulatory environment of certain major jurisdictions in which AEP operates. Several public utility subsidiaries operate in more than one jurisdiction. See Note 4 to the consolidated financial statements, entitled *Rate Matters*, included in the 2010 Annual Reports, for more information regarding pending rate matters.

Indiana: I&M provides retail electric service in Indiana at bundled rates approved by the IURC, with rates set on a cost-of-service basis. Indiana provides for timely fuel and purchased power cost recovery through a fuel cost recovery mechanism.

Ohio: CSPCo and OPCo provide "default" retail electric service to customers at unbundled rates pursuant to the Ohio Act. CSPCo and OPCo exclusively provide distribution and transmission services to retail customers within their service territories at cost-based rates approved by the PUCO. Transmission services are provided at OATT rates based on rates established by the FERC. CSPCo and OPCo's generation/supply rates are subject to their Electric Security Plans that the PUCO modified and approved in a March 2009 order. The order established standard service offer rates in effect through 2011. The order also provides a fuel adjustment clause for the three-year period of the ESP. The order has been appealed by various parties to the Supreme Court of Ohio. Although the Supreme Court of Ohio has rejected or dismissed a number of procedural and other challenges to the order, the order remains on appeal with that Court with oral arguments scheduled in February 2011. In January 2011, CSPCo and OPCo filed an application with the FERC requesting approval for CSPCo to merge into OPCo, effective in October 2011. Decisions are pending from the PUCO and the FERC. Approval of the merger will not affect their rates until such time as the PUCO approves new rates.

Oklahoma: PSO provides retail electric service in Oklahoma at bundled rates approved by the OCC. PSO's rates are set on a cost-of-service basis. Fuel and purchased energy costs above or below the amount included in base rates are recovered or refunded by applying a fuel adjustment factor to retail kilowatt-hour sales. The factor is generally adjusted annually and is based upon forecasted fuel and purchased energy costs. Over or under collections of fuel costs for prior periods are returned to or recovered from customers in the year following when new annual factors are established.

Texas: Retail customers in TCC's and TNC's ERCOT service area of Texas are served through non-affiliated Retail Electric Providers ("REPs"). TCC and TNC provide transmission and distribution service on a cost-of-service basis at rates approved by the PUCT and wholesale transmission service under tariffs approved by the FERC consistent with PUCT rules. Effective September 2009, competition in the SPP area of Texas has been delayed until certain steps defined by statute and by PUCT rule have been accomplished. As such, the PUCT continues to approve base and fuel rates for SWEPCo's Texas operations on a cost of service basis.

Virginia: APCo currently provides retail electric service in Virginia at unbundled rates approved by the VSCC. Virginia generally allows for timely recovery of fuel costs through a fuel adjustment clause. Transmission services are provided at OATT rates based on rates established by the FERC. APCo is permitted to retain a minimum of 25% of the margins from its off-system sales with the remaining margins from such sales credited against its fuel adjustment clause factor with a true-up to actual. In addition to base rates and fuel cost recovery, APCo is permitted to recover a variety of costs through rate adjustment clauses.

West Virginia: APCo and WPCo provide retail electric service at bundled rates approved by the WVPSC, with rates set on a cost-of-service basis. West Virginia generally allows for timely recovery of fuel costs through an expanded net energy clause which trues-up to actual expenses.

Other Jurisdictions: The public utility subsidiaries of AEP also provide service at cost based regulated bundled rates in Arkansas, Kentucky, Louisiana and Tennessee and regulated unbundled rates in Michigan. These jurisdictions provide for the timely recovery of fuel costs through fuel adjustment clauses that true-up to actual expenses.

The following table illustrates certain regulatory information with respect to the states in which the public utility subsidiaries of AEP operate:

Jurisdiction	Percentage of AEP System Retail Revenues (1)	Percentage of OSS Profits Shared with Ratepayers	AEP Utility Subsidiaries Operating in that Jurisdiction	Authorized Return on Equity (2)
Ohio	32%	No sharing included in ESPs	OPCo	(3)
			CSPCo	(3)
Texas	12%	Not Applicable in ERCOT	TCC (4)	9.96%
			TNC (4)	9.96%
		90% in SPP	SWEPCo	10.33%
Virginia	12%	75%	APCo	10.53%
West Virginia	11%	100%	APCo	10.50%
			WPCo	10.50%
Oklahoma	10%	75%	PSO	10.15%
Indiana	9%	50% after certain level (5)	I&M	10.50%
Kentucky	5%	60% below and above certain level (6)	KPCo	10.50%
Louisiana	4%	50% to 100% after certain levels (7)	SWEPCo	10.57%
Arkansas	2%	50% to 100% after certain levels (8)	SWEPCo	10.25%
Michigan	2%	75%	I&M	10.35%
Tennessee	1%	Not Applicable	KgPCo	12.00%

(1) Represents the percentage of revenues from sales to retail customers from AEP utility companies operating in each state to the total AEP System revenues from sales to retail customers for the year ended December 31, 2010.

(2) Identifies the predominant authorized return on equity and may not include other, less significant, permitted recovery. Actual return on equity varies from authorized return on equity.

(3) CSPCo's and OPCo's generation revenues are governed by its Electric Security Plans (ESPs) filed and approved by the PUCO. Starting in January 2009, the ESPs became effective which authorized rate increases during the ESP period, subject to caps that limit the rate increases for CSPCo to 7% in 2009, 6% in 2010 and 6% in 2011 and for OPCo to 8% in 2009, 7% in 2010 and 8% in 2011. Some rate components and increases are exempt from the cap limitations. The ESPs also provided for a fuel adjustment clause for the three-year period of the ESP.

(4) Operating in the ERCOT region of Texas and consists of distribution and transmission functions. Generation operations were divested in compliance with the Texas electric restructuring.

(5) There is an annual $37.5 million credit established for off-system sales in base rates. If the off-system sales profits exceed the amount built into base rates, I&M reimburses ratepayers 50% of the excess.

(6) Starting in July 2010, there is an annual $15.3 million credit established for off-system sales in base rates. If the monthly off-system sales profits do not meet the monthly level built into base rates, ratepayers reimburse KPCo 60% of the shortfall. If the monthly off-system sales profits exceed the monthly level built into base rates, KPCo reimburses ratepayers 60% of the excess.

(7) Below $874,000, 100% is shared with customers; from $874,001 to $1,314,000, 85% is shared with customers; above $1,314,000, 50% is shared with customers.

(8) Below $758,600, 100% is shared with customers; from $758,601 to $1,167,078, 85% is shared with customers; above $1,167,078, 50% is shared with customers.

FERC

Under the FPA, the FERC regulates rates for interstate power sales at wholesale, transmission of electric power, accounting and other matters, including construction and operation of hydroelectric projects. The FERC regulations require AEP to provide open access transmission service at FERC-approved rates. The FERC also regulates unbundled transmission service to retail customers. The FERC also regulates the sale of power for resale in interstate commerce by (i) approving contracts for wholesale sales to municipal and cooperative utilities and (ii) granting authority to public utilities to sell power at wholesale at market-based rates upon a showing that the seller lacks the ability to improperly influence market prices. Except for wholesale power that AEP delivers within its control area of the SPP, AEP has market-rate authority from the FERC, under which much of its wholesale marketing activity takes place. The FERC requires each public utility that owns or controls interstate transmission facilities to, directly or through an RTO, file an open access network and point-to-point transmission tariff that offers services comparable to the utility's own uses of its transmission system. The FERC also requires all transmitting utilities, directly or through an RTO, to establish an OASIS, which electronically posts transmission information such as available capacity and prices, and requires utilities to comply with Standards of Conduct that prohibit utilities' transmission employees from providing non-public transmission information to the utility's marketing employees.

The FERC oversees RTOs, entities created to operate, plan and control utility transmission assets. Order 2000 also prescribes certain characteristics and functions of acceptable RTO proposals. The AEP East Companies are members of PJM. SWEPCo and PSO are members of SPP.

The FERC has jurisdiction over the issuances of securities of most of our public utility subsidiaries, the acquisition of securities of utilities, the acquisition or sale of certain utility assets, and mergers with another electric utility or holding company. In addition, both the FERC and state regulators are permitted to review the books and records of any company within a holding company system. EPACT gives the FERC limited "backstop" transmission siting authority as well as increased utility merger oversight.

COMPETITION

Under current Ohio legislation, electric generation is sold in a competitive market in Ohio, and our native load customers in Ohio have the ability to switch to alternative suppliers for their electric generation service. Competitive power suppliers are targeting retail customers by offering alternative generation service. A growing number of CSPCo's commercial retail customers have switched to alternative generation providers while additional Ohio customers have provided notice of their intent to switch. In 2010, CSPCo lost about 3% of its total load due to customer switching. These evolving market conditions will continue to impact CSPCo's results of operations. To date, OPCo's customer losses have been insignificant. In February 2010, the PUCO granted a retail supply subsidiary of AEP a certificate to operate as a competitive retail electric service provider in Ohio.

The public utility subsidiaries of AEP, like the electric industry generally, face competition in the sale of available power on a wholesale basis, primarily to other public utilities and power marketers. The Energy Policy Act of 1992 was designed, among other things, to foster competition in the wholesale market by creating a generation market with fewer barriers to entry and mandating that all generators have equal access to transmission services. As a result, there are more generators able to participate in this market. The principal factors in competing for wholesale sales are price (including fuel costs), availability of capacity and power and reliability of service.

AEP's public utility subsidiaries also compete with self-generation and with distributors of other energy sources, such as natural gas, fuel oil and coal, within their service areas. The primary factors in such competition are price, reliability of service and the capability of customers to utilize sources of energy other than electric power. With respect to competing generators and self-generation, the public utility subsidiaries of AEP believe that they generally maintain a favorable competitive position. With respect to alternative sources of energy, the public utility subsidiaries of AEP believe that the reliability of their service and the limited ability of customers to substitute other cost-effective sources for electric power place them in a favorable competitive position, even though their prices may be higher than the costs of some other sources of energy.

Significant changes in the global economy have led to increased price competition for industrial customers in the United States, including those served by the AEP System. Some of these industrial customers have requested price reductions from their suppliers of electric power. In addition, industrial customers that are downsizing or reorganizing often close a facility based upon its costs, which may include, among other things, the cost of electric power. The public utility subsidiaries of AEP cooperate with such customers to meet their business needs through, for example, providing various off-peak or interruptible supply options pursuant to tariffs filed with, and approved by, the various state commissions. Occasionally, these rates are negotiated with the customer, and then filed with the state commissions for approval.

SEASONALITY

The sale of electric power is generally a seasonal business. In many parts of the country, demand for power peaks during the hot summer months, with market prices also peaking at that time. In other areas, power demand peaks during the winter. The pattern of this fluctuation may change due to the nature and location of AEP's facilities and the terms of power sale contracts into which AEP enters. In addition, AEP has historically sold less power, and consequently earned less income, when weather conditions are milder. Unusually mild weather in the future could diminish AEP's results of operations and may impact its financial condition. Conversely, unusually extreme weather conditions could increase AEP's results of operations.

AEP RIVER OPERATIONS

Our AEP River Operations Segment transports coal and dry bulk commodities primarily on the Ohio, Illinois, and lower Mississippi rivers. Almost all of our customers are nonaffiliated third parties who obtain the transport of coal and dry bulk commodities for various uses. We charge these customers market rates for the purpose of making a profit. Depending on market conditions and other factors, including barge availability, we permit AEP utility subsidiary affiliates to use certain of our equipment at rates that reflect our cost. Our affiliated utility customers procure the transport of coal for use as fuel in their respective generating plants. We charge affiliated customers rates that reflect our costs. AEP River Operations includes approximately 2,581 barges, 45 towboats and 26 harbor boats that we own or lease. These assets are separate from the barges and towboats dedicated exclusively to transporting coal for use as fuel in our own generating facilities discussed under the prior segment. See *Item 1 – Utility Operations - Electric Generation —Fuel Supply—Coal and Lignite.*

Competition within the barging industry for major commodity contracts is intense, with a number of companies offering transportation services in the waterways we serve. We compete with other carriers primarily on the basis of commodity shipping rates, but also with respect to customer service, available routes, value-added services (including scheduling convenience and flexibility), information timeliness and equipment. The industry continues to experience consolidation. The resulting companies increasingly offer the widespread geographic reach necessary to support major national customers. Demand for barging services can be seasonal, particularly with respect to the movement of harvested agricultural commodities (beginning in the late summer and extending through the fall). Cold winter weather and inefficient older river locks operated by others may also limit our operations when certain of the waterways we serve are closed.

Our transportation operations are subject to regulation by the U.S. Coast Guard, federal laws, state laws and certain international conventions. Legislation has been proposed that could make our towboats subject to inspection by the U.S. Coast Guard.

GENERATION AND MARKETING

Our Generation and Marketing Segment consists of non-utility generating assets and a competitive power supply and energy trading and marketing business. We enter into short and long-term transactions to buy or sell capacity, energy and ancillary services primarily in the ERCOT market, and to a lesser extent Ohio in PJM and MISO. As of December 31, 2010, the assets utilized in this segment included approximately 310 MW of company-owned domestic wind power facilities, 177 MW of domestic wind power from long-term purchase power agreements and 377 MW of coal-fired capacity which was obtained through an agreement effective through 2027 that transfers TNC's interest in the Oklaunion power station to AEP Energy Partners, Inc. In 2006, TNC transferred its coal-fired generation capacity to comply with the separation requirements of the Texas Act. The power obtained from the Oklaunion power station is marketed and sold in ERCOT. We are regulated by the PUCT for transactions inside ERCOT and by the FERC for transactions outside of ERCOT. While peak load in ERCOT typically occurs in the summer, we do not necessarily expect seasonal variation in our operations. In 2010, we started operations of a retail energy business in the State of Ohio. The purpose of this operation is to sell competitive power supply to residential, commercial and industrial customers in the deregulated areas of Ohio.

ITEM 1A. RISK FACTORS

General Risks of Our Regulated Operations

We may not be able to recover the costs of our substantial planned investment in capital improvements and additions. *(Applies to each registrant.)*

Our business plan calls for extensive investment in capital improvements and additions, including the installation of environmental upgrades and retrofits, construction and/or acquisition of additional generation units and transmission facilities, modernizing existing infrastructure as well as other initiatives. Our public utility subsidiaries currently provide service at rates approved by one or more regulatory commissions. If these regulatory commissions do not approve adjustments to the rates we charge, we would not be able to recover the costs associated with our planned extensive investment. This would cause our financial results to be diminished. While we may seek to limit the impact of any denied recovery by attempting to reduce the scope of our capital investment, there can be no assurance as to the effectiveness of any such mitigation efforts, particularly with respect to previously incurred costs and commitments.

We may not fully recover all of the investment in and expenses related to the Turk Plant. *(Applies to AEP and SWEPCo)*

SWEPCo is in the process of building the John W. Turk Plant (the "Turk Plant") in southwest Arkansas and holds a 73% ownership interest in the planned 600MW coal-fired generating facility. Its construction and anticipated operation has resulted in numerous legal challenges, including:

- the validity of the air permit issued by the Arkansas Pollution Control and Ecology Commission in connection with the operation of the Turk Plant;
- the validity of the wetlands permit issued by the U.S. Army Corps of Engineers in connection with the construction and operation of the Turk Plant;
- the validity of the authority granted by the APSC to build three transmission lines and facilities needed to transmit power from the Turk Plant;
- whether SWEPCo is required to obtain APSC approval to construct the Turk Plant without pursuing authority to seek recovery of the originally approved 88 MW portion of Turk Plant costs in Arkansas retail rates; and
- a complaint filed in the Federal District Court for the Western District of Arkansas against SWEPCo, the U.S. Army Corps of Engineers, the U.S. Department of Interior and the U.S. Fish and Wildlife Service seeking a temporary restraining order and preliminary injunction to stop construction of the Turk Plant asserting claims of violations of various federal and state laws.

If SWEPCo is unable to complete the Turk Plant construction and place the Turk Plant in service or if SWEPCo cannot recover all of its investment in and expenses related to the Turk Plant, it would materially reduce future net income and cash flows and materially impact financial condition.

Our request for rate recovery in Ohio for distribution service may not be approved in its entirety. *(Applies to AEP, CSPCo and OPCo)*

In January 2011, CSPCo and OPCo filed a notice of intent with the PUCO to file for an annual increase in distribution rates of $34 million and $59 million, respectively, either as individual companies, or, if their proposed merger is approved, as a single merged entity. The increase is based upon an 11.15% return on common equity to be effective January 2012. If the PUCO denies all or part of the requested rate recovery, it could reduce future net income and cash flows.

Our request for rate recovery in Ohio for generation service may not be approved in its entirety. *(Applies to AEP, CSPCo and OPCo)*

In January 2011, CSPCo and OPCo filed an application with the PUCO to approve the new ESP that includes a standard service offer pricing for generation effective with the first billing cycle of January 2012 through the last billing cycle of May 2014. The requested increase in 2012 is $54 million and in 2013 is $106 million. If the PUCO denies all or part of the requested rate recovery, it could reduce future net income and cash flows.

Ohio may require us to refund revenue that we have collected. *(Applies to AEP, CSPCo and OPCo)*

Ohio law requires that the PUCO determine on an annual basis if rate adjustments included in prior orders resulted in significantly excessive earnings. If the rate adjustments result in significantly excessive earnings, the excess amount could be returned to customers. In September 2010, CSPCo and OPCo filed their 2009 significantly excessive earnings filings with the PUCO. In January 2011, the PUCO ruled that CSPCo generated approximately $43 million in significantly excessive earnings during 2009. The ruling is subject to rehearing by the PUCO and could be appealed in the courts. If rehearing or a final appeal, if any, results in findings of additional significantly excessive earnings, then further amounts will be returned to customers. CSPCo and OPCo must file their 2010 significantly excessive earnings filings with the PUCO. If the PUCO determines that CSPCo's and/or OPCo's 2010 earnings were significantly excessive, CSPCo and/or OPCo may be required to return a portion of their revenues to customers.

Ohio may require us to refund fuel costs that we have collected. *(Applies to OPCo)*

The PUCO selected an outside consultant to conduct an audit of recovery under the fuel adjustment clause for the period of January 2009 through December 2009. The audit report included a recommendation that the PUCO should review whether any proceeds from a 2008 coal contract settlement agreement which totaled $72 million should reduce OPCo's under-recovery balance. Of the total proceeds, approximately $58 million was recognized as a reduction to fuel expense prior to 2009 and $14 million reduced fuel expense in 2009 and 2010. If the PUCO orders any portion of the $58 million or other future adjustments be used to reduce the current year fuel adjustment clause deferral, it would reduce future net income and cash flows and impact financial condition.

Ohio may require us to refund rider revenue that we have collected. *(Applies to CSPCo and OPCo)*

The PUCO approved recovery of an Economic Development Rider (EDR) by CSPCo and OPCo. An intervenor in that proceeding has filed a notice of appeal of that award with the Supreme Court of Ohio. As of December 31, 2010, CSPCo and OPCo have incurred $38 million and $30 million, respectively, in EDR costs including carrying costs. If CSPCo and OPCo are not ultimately permitted to recover their deferrals it would reduce future net income and cash flows and impact financial condition.

Our request for rate recovery in West Virginia may not be approved in its entirety. *(Applies to AEP and APCo)*

In May 2010, APCo and WPCo filed a request with the WVPSC to increase annual base rates by $156 million based on an 11.75% return on common equity to be effective March 2011. If the WVPSC denies all or part of the requested rate recovery, it could reduce future net income and cash flows.

Oklahoma may require us to refund fuel costs that we have collected. *(Applies to PSO)*

In July 2009, the OCC initiated a proceeding to review PSO's fuel and purchased power adjustment clause for the calendar year 2008 and also initiated a prudence review of the related costs. In March 2010, the Oklahoma Attorney General and an intervenor recommended the fuel clause adjustment rider be amended to decrease the shareholder's portion of off-system sales margins from 25% to 10%. That intervenor also recommended that the OCC conduct a comprehensive review of all affiliate transactions during 2007 and 2008. In July 2010, additional testimony regarding the 2007 transfer of ERCOT trading contracts to AEP Energy Partners was filed. Included in this testimony were unquantified refund recommendations relating to re-pricing of contract transactions. If the OCC were to issue an unfavorable decision, it would reduce future net income and cash flows and impact financial condition.

Our future access to assets used to serve a major customer is in question. *(Applies to I&M)*

Since 1975 I&M has leased certain energy delivery assets from the City of Fort Wayne, Indiana under a long-term lease that expired on February 28, 2010. As a result of a court-sponsored mediation process, I&M agreed to purchase the leased assets from Fort Wayne. The agreement was signed in October 2010 and is subject to approval by the IURC. If the IURC does not approve the agreement or the recovery of the costs resulting from the agreement or the lease, it could reduce future net income and cash flows.

We may not recover costs incurred to begin construction on projects that are canceled. *(Applies to each registrant)*

Our business plan for the construction of new projects involves a number of risks, including construction delays, nonperformance by equipment and other third party suppliers, and increases in equipment and labor costs. To limit the risks of these construction projects, we enter into equipment purchase orders and construction contracts and incur engineering and design service costs in advance of receiving necessary regulatory approvals and/or siting or environmental permits. If any of these projects is canceled for any reason, including our failure to receive necessary regulatory approvals and/or siting or environmental permits, we could incur significant cancellation penalties under the equipment purchase orders and construction contracts. In addition, if we have recorded any construction work or investments as a regulatory asset we may need to impair that asset in the event the project is canceled.

Rate regulation may delay or deny full recovery of capital improvements, additions and other costs. *(Applies to each registrant.)*

Our public utility subsidiaries currently provide service at rates approved by one or more regulatory commissions. These rates are generally regulated based on an analysis of the applicable utility's expenses incurred in a test year. Thus, commission-approved rates may or may not match a utility's expenses at any given time. There may also be a delay between the timing of when these costs are incurred and when these costs are recovered. Traditionally, we have financed capital investments and improvements until the new asset was placed in service. Provided the asset was found to be a prudent investment, the asset was then added to rate base and entitled to a return through rate recovery. Long lead times in construction, the high costs of plant and equipment and difficult capital markets have heightened the risks involved in our capital investments and improvements. While we are actively pursuing strategies to accelerate rate recognition of investments and cash flow, including pre-approvals, a return on construction work in progress, rider/trackers, formula rates and the inclusion of future test-year projections into rates, there can be no assurance that these will be adopted, that the applicable regulatory commission will judge all of our costs to have been prudently incurred or that the regulatory process in which rates are determined will be done in a timely manner.

Certain of our revenues and results of operations are subject to risks that are beyond our control. *(Applies to each registrant.)*

Our operations are structured to comply with all applicable federal and state laws and regulations and we take measures to minimize the risk of significant disruptions. Material disruptions at one or more of our operational facilities, however, could negatively impact our revenues, operating and capital expenditures and results of operations. Such events may also create additional risks related to the supply and/or cost of equipment and materials. We could experience unexpected but significant interruption due to several events, including:

- major facility or equipment failure;
- an environmental event such as a serious spill or release;
- fires, floods, droughts, earthquakes, hurricanes or other natural disasters;
- wars, terrorist acts or threats and other catastrophic events;
- significant health impairments or disease events, and;
- other serious operational problems.

We are exposed to nuclear generation risk. *(Applies to AEP and I&M.)*

Through I&M, we own the Cook Plant. It consists of two nuclear generating units for a rated capacity of 2,191 MW, or 8-9% of the electricity we generate. We are, therefore, subject to the risks of nuclear generation, which include the following:

- the potential harmful effects on the environment and human health resulting from the operation of nuclear facilities and the storage, handling and disposal of radioactive materials such as spent nuclear fuel;

- limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with our nuclear operations;

- uncertainties with respect to contingencies and assessment amounts if insurance coverage is inadequate (federal law requires owners of nuclear units to purchase the maximum available amount of nuclear liability insurance and potentially contribute to the losses of others); and,

- uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of their licensed lives.

There can be no assurance that I&M's preparations or risk mitigation measures will be adequate if and when these risks are triggered.

The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities. In the event of non-compliance, the NRC has the authority to impose fines or shut down a unit, or both, depending upon its assessment of the severity of the situation, until compliance is achieved. Revised safety requirements promulgated by the NRC could necessitate substantial capital expenditures at nuclear plants such as ours. In addition, although we have no reason to anticipate a serious nuclear incident at our plants, if an incident did occur, it could harm our results of operations or financial condition. A major incident at a nuclear facility anywhere in the world could cause the NRC to limit or prohibit the operation or licensing of any domestic nuclear unit. Moreover, a major incident at any nuclear facility in the U.S. could require us to make material contributory payments.

Costs associated with the operation (including fuel), maintenance and retirement of nuclear plants continue to be more significant and less predictable than costs associated with other sources of generation, in large part due to changing regulatory requirements and safety standards, availability of nuclear waste disposal facilities and experience gained in the operation of nuclear facilities. Costs also may include replacement power, any unamortized investment at the end of the useful life of the Cook Plant (whether scheduled or premature), the carrying costs of that investment and retirement costs. Our ability to obtain adequate and timely recovery of costs associated with the Cook Plant is not assured.

The different regional power markets in which we compete or will compete in the future have changing market and transmission structures, which could affect our performance in these regions. *(Applies to each registrant.)*

Our results are likely to be affected by differences in the market and transmission structures in various regional power markets. The rules governing the various regional power markets, including SPP and PJM, may also change from time to time which could affect our costs or revenues. Because the manner in which RTOs will evolve remains unclear, we are unable to assess fully the impact that changes in these power markets may have on our business.

The amount we charged third parties for using our transmission facilities is subject to refund. *(Applies to AEP, APCo, CSPCo, I&M and OPCo.)*

In July 2003, the FERC issued an order directing PJM and MISO to make compliance filings for their respective tariffs to eliminate the transaction-based charges for through and out (T&O) transmission service on transactions where the energy is delivered within those RTOs. To mitigate the impact of lost T&O revenues, the FERC approved temporary replacement seams elimination cost allocation (SECA) transition rates beginning in December 2004 and extending through March 2006. Because intervenors objected to this decision, the SECA fees we collected ($220 million) are subject to refund. Some claims for refund have been settled, and we have recorded a provision for estimated settlement refunds for the remaining unsettled $108 million of gross SECA revenues collected. Any payments in excess of the reserve balance could harm our results of operations and financial position.

We could be subject to higher costs and/or penalties related to mandatory reliability standards. *(Applies to each registrant.)*

As a result of EPACT, owners and operators of the bulk power transmission system are subject to mandatory reliability standards promulgated by the North American Electric Reliability Corporation and enforced by the FERC. These standards, which previously were being applied on a voluntary basis, became mandatory in June 2007. The standards are based on the functions that need to be performed to ensure the bulk power system operates reliably and is guided by reliability and market interface principles. Compliance with new reliability standards may subject us to higher operating costs and/or increased capital expenditures. While we expect to recover costs and expenditures from customers through regulated rates, there can be no assurance that the applicable commissions will approve full recovery in a timely manner. If we were found not to be in compliance with the mandatory reliability standards, we could be subject to sanctions, including substantial monetary penalties, which likely would not be recoverable from customers through regulated rates.

At times, demand for power could exceed our supply capacity. *(Applies to each registrant.)*

We are currently obligated to supply power in parts of eleven states. From time to time, because of unforeseen circumstances, the demand for power required to meet these obligations could exceed our available generation capacity. If this occurs, we would have to buy power from the market. This would increase the pressure on our short-term debt financing capacity in times of tight liquidity. We may not always have the ability to pass these costs on to our customers, and the time lag between incurring costs and recovery can be long. Since these situations most often occur during periods of peak demand, it is possible that the market price for power at that time would be very high. Even if a supply shortage were brief, we could suffer substantial losses that could reduce our results of operations.

Risks Related to Market, Economic or Financial Volatility

If we are unable to access capital markets on reasonable terms, it could have an adverse impact on our net income, cash flows and financial condition. *(Applies to each registrant)*

We rely on access to capital markets as a significant source of liquidity for capital requirements not satisfied by operating cash flows. Volatility and reduced liquidity in the financial markets could affect our ability to raise capital and fund our capital needs, including construction costs and refinancing maturing indebtedness. In addition, if capital is available only on less than reasonable terms or to borrowers whose creditworthiness is better than ours, capital costs could increase materially. Restricted access to capital markets and/or increased borrowing costs could have an adverse impact on net income, cash flows and financial condition.

Downgrades in our credit ratings could negatively affect our ability to access capital and/or to operate our power trading businesses. *(Applies to each registrant)*

The credit ratings agencies periodically review our capital structure and the quality and stability of our earnings. Any negative ratings actions could constrain the capital available to us and could limit our access to funding for our operations. Our business is capital intensive, and we are dependent upon our ability to access capital at rates and on terms we determine to be attractive. In periods of market turmoil, access to capital is difficult for all borrowers. If our ability to access capital becomes significantly constrained, our interest costs will likely increase and our financial condition could be harmed and future results of operations could be adversely affected.

Our power trading business relies on the investment grade ratings of our individual public utility subsidiaries' senior unsecured long-term debt. Most of our counterparties require the creditworthiness of an investment grade entity to stand behind transactions. If those ratings were to decline below investment grade, our ability to operate our power trading business profitably would be diminished because we would likely have to deposit cash or cash-related instruments which would reduce our profits.

Our pension plan will require additional significant contributions. *(Applies to each registrant.)*

The performance of the capital markets affects the value of the assets that are held in trust to satisfy future obligations under our defined benefit pension plan. The volatility of the capital markets in the past years has led to a decline in the market value of these assets. Also, a decline in interest rates on corporate bonds in 2010 has impacted the benchmark discount rate in a way that results in a higher calculated pension liability. Accordingly, our future required contributions to fund obligations under our defined benefit plan could increase significantly.

AEP has no income or cash flow apart from dividends paid or other obligations due it from its subsidiaries. *(Applies to AEP.)*

AEP is a holding company and has no operations of its own. Its ability to meet its financial obligations associated with its indebtedness and to pay dividends on its common stock is primarily dependent on the earnings and cash flows of its operating subsidiaries, primarily its regulated utilities, and the ability of its subsidiaries to pay dividends to, or repay loans from, AEP. Its subsidiaries are separate and distinct legal entities that have no obligation (apart from loans from AEP) to provide AEP with funds for its payment obligations, whether by dividends, distributions or other payments. Payments to AEP by its subsidiaries are also contingent upon their earnings and business considerations. In addition, any payment of dividends, distributions or advances by the utility subsidiaries to AEP could be subject to regulatory restrictions. AEP indebtedness and common stock dividends are structurally subordinated to all subsidiary indebtedness and preferred stock obligations.

Our operating results may fluctuate on a seasonal or quarterly basis and with general economic conditions. *(Applies to each registrant.)*

Electric power generation is generally a seasonal business. In many parts of the country, demand for power peaks during the hot summer months, with market prices also peaking at that time. In other areas, power demand peaks during the winter. As a result, our overall operating results in the future may fluctuate substantially on a seasonal basis. The pattern of this fluctuation may change depending on the terms of power sale contracts that we enter into. In addition, we have historically sold less power, and consequently earned less income, when weather conditions are milder. Unusually mild weather in the future could diminish our results of operations and harm our financial condition. Conversely, unusually extreme weather conditions could increase AEP's results of operations in a manner that would not likely be sustainable.

Further, deteriorating economic conditions generally result in reduced consumption by our customers, particularly industrial customers who may curtail operations or cease production entirely, while an expanding economic environment generally results in increased revenues. As a result, our overall operating results in the future may fluctuate on the basis of prevailing economic conditions.

Failure to attract and retain an appropriately qualified workforce could harm our results of operations. *(Applies to each registrant.)*

Certain events, such as an aging workforce without appropriate replacements, mismatch of skillset or complement to future needs, or unavailability of contract resources may lead to operating challenges and increased costs. The challenges include lack of resources, loss of knowledge and a lengthy time period associated with skill development. In this case, costs, including costs for contractors to replace employees, productivity costs and safety costs, may rise. Failure to hire and adequately train replacement employees, including the transfer of significant internal historical knowledge and expertise to the new employees, or the future availability and cost of contract labor may adversely affect the ability to manage and operate our business. If we are unable to successfully attract and retain an appropriately qualified workforce, our results of operations could be negatively affected.

Parties we have engaged to provide construction materials or services may fail to perform their obligations, which could harm our results of operations. *(Applies to each registrant.)*

Our business plan calls for extensive investment in capital improvements and additions, including the installation of environmental upgrades, construction of additional generation units and transmission facilities as well as other initiatives. We are exposed to the risk of substantial price increases in the costs of materials used in construction. We have engaged numerous contractors and entered into a large number of agreements to acquire the necessary materials and/or obtain the required construction related services. As a result, we are also exposed to the risk that these contractors and other counterparties could breach their obligations to us. Should the counterparties to these arrangements fail to perform, we may be forced to enter into alternative arrangements at then-current market prices that may exceed our contractual prices and almost certainly cause delays in that and related projects. Although our agreements are designed to mitigate the consequences of a potential default by the counterparty, our actual exposure may be greater than these mitigation provisions. This would cause our financial results to be diminished, and we might incur losses or delays in completing construction.

Changes in commodity prices and the costs of transport may increase our cost of producing power or decrease the amount we receive from selling power, harming our financial performance. *(Applies to each registrant.)*

We are exposed to changes in the price and availability of coal and the price and availability to transport coal because most of our generating capacity is coal-fired. We have contracts of varying durations for the supply of coal for most of our existing generation capacity, but as these contracts end or otherwise are not honored, we may not be able to purchase coal on terms as favorable as the current contracts. Similarly, we are exposed to changes in the price and availability of emission allowances. We use emission allowances based on the amount of coal we use as fuel and the reductions achieved through emission controls and other measures. According to our estimates, we have procured sufficient emission allowances to cover nearly all of our projected needs for the next two years as well as a majority of our needs beyond that timeframe. At some future point, additional costs may be incurred if forthcoming regulation changes require supplemental allowances for compliance. If and when we obtain additional allowances those purchases may not be on as favorable terms as those currently obtained.

We also own natural gas-fired facilities, which increases our exposure to market prices of natural gas. Natural gas prices tend to be more volatile than prices for other fuel sources. Our ability to make off-system sales at a profit is highly dependent on the price of natural gas. As the price of natural gas falls, other market participants that utilize natural gas-fired generation will be able to offer electricity at increasingly competitive prices relative to our off-system sales prices, so the margins we realize from sales will be lower and, on occasion, we may need to curtail operation of marginal plants.

Prices for coal, natural gas and emission allowances have shown material upward and downward swings in the recent past. Changes in the cost of coal, emission allowances or natural gas and changes in the relationship between such costs and the market prices of power will affect our financial results. Since the prices we obtain for power may not change at the same rate as the change in coal, emission allowances or natural gas costs, we may be unable to pass on the changes in costs to our customers.

In addition, actual power prices and fuel costs will differ from those assumed in financial projections used to value our trading and marketing transactions, and those differences may be material. As a result, our financial results may be diminished in the future as those transactions are marked to market.

Risks Relating to State Restructuring

Our customers have recently begun to select alternative electric generation service providers, as allowed by Ohio legislation. *(Applies to AEP and CSPCo)*

Under current Ohio legislation, electric generation is sold in a competitive market in Ohio, and our native load customers in Ohio have the ability to switch to alternative suppliers for their electric generation service. Competitive power suppliers are targeting retail customers by offering alternative generation service. A growing number of CSPCo's commercial retail customers have switched to alternative generation providers while additional Ohio customers have provided notice of their intent to switch. In 2010, CSPCo lost about 3% of its total load due to customer switching. To date, OPCo's losses have not been significant. These evolving market conditions will continue to impact CSPCo's results of operations.

There is uncertainty as to our recovery of stranded costs resulting from industry restructuring in Texas. *(Applies to AEP.)*

Restructuring legislation in Texas required utilities with stranded costs to use market-based methods to value certain generating assets for determining stranded costs. We elected to use the sale of assets method to determine the market value of TCC's generation assets for stranded cost purposes. In general terms, the amount of stranded costs under this market valuation methodology is the amount by which the book value of generating assets, including regulatory assets and liabilities that were not securitized, exceeds the market value of the generation assets, as measured by the net proceeds from the sale of the assets. In May 2005, TCC filed its stranded cost quantification application with the PUCT seeking recovery of $2.4 billion of net stranded generation costs and other recoverable true-up items. A final order was issued in April 2006. In the final order, the PUCT determined TCC's net stranded generation costs and other recoverable true-up items to be approximately $1.475 billion. We have appealed the PUCT's final order seeking additional recovery consistent with the Texas Restructuring Legislation and related rules, other parties have appealed the PUCT's final order as unwarranted or too large. Management cannot predict the ultimate outcome of any future court appeals or any future remanded PUCT proceeding.

Collection of our revenues in Texas is concentrated in a limited number of REPs. *(Applies to AEP.)*

Our revenues from the distribution of electricity in the ERCOT area of Texas are collected from REPs that supply the electricity we distribute to their customers. Currently, we do business with approximately one hundred REPs. In 2010, TCC's largest customer accounted for 25% of its operating revenue and its second largest customer accounted for 13% of its operating revenue; TNC's largest customer (a non-utility affiliate) accounted for 29% of its operating revenues and its second largest customer accounted for 16% of its operating revenues. Adverse economic conditions, structural problems in the Texas market or financial difficulties of one or more REPs could impair the ability of these REPs to pay for our services or could cause them to delay such payments. We depend on these REPs for timely remittance of payments. Any delay or default in payment could adversely affect the timing and receipt of our cash flows and thereby have an adverse effect on our liquidity.

Risks Related to Owning and Operating Generation Assets and Selling Power

Our costs of compliance with existing environmental laws are significant. *(Applies to each registrant)*

Our operations are subject to extensive federal, state and local environmental statutes, rules and regulations relating to air quality, water quality, waste management, natural resources and health and safety. Approximately 90% of the electricity generated by the AEP system is produced by the combustion of fossil fuels. Emissions of nitrogen and sulfur oxides, mercury and particulates from fossil fueled generating plants are potentially subject to increased regulations, controls and mitigation expenses. Compliance with these legal requirements requires us to commit significant capital toward environmental monitoring, installation of pollution control equipment, emission fees and permits at all of our facilities. These expenditures have been significant in the past, and we expect that they will increase in the future. Costs of compliance with environmental regulations could adversely affect our net income and financial position, especially if emission and/or discharge limits are tightened, more extensive permitting requirements are imposed, additional substances become regulated and the number and types of assets we operate increase. While we expect to recover our expenditures for pollution control technologies, replacement generation and associated operating costs from customers through regulated rates (in regulated jurisdictions) or market prices, without such recovery those costs could reduce our future net income and cash flows, and possibly harm our financial condition.

Regulation of CO_2 emissions, either through legislation or by the Federal EPA, could materially increase costs to us and our customers or cause some of our electric generating units to be uneconomical to operate or maintain. *(Applies to each registrant)*

In June 2009, the U.S. House of Representatives passed the American Clean Energy Security Act (ACES). ACES is a comprehensive energy and global warming bill that includes a number of provisions that would directly affect our business, including energy efficiency and renewable electricity standards, funding for carbon capture and sequestration demonstration projects, CO_2 emission standards, and an economy-wide cap and trade program for large sources of CO_2 emissions that would reduce emissions by 17% in 2020 and just over 80% by 2050 from 2005 levels. Costs of compliance with the proposed legislation could adversely affect our net income and financial position. This legislation did not become law.

Separately, in December 2009, the Federal EPA issued a final endangerment finding under the CAA regarding emissions from motor vehicles. Several groups have filed challenges to the endangerment finding. The endangerment finding will lead to regulation of CO_2 and other gases under existing laws. Management believes some policy approaches being discussed would have significant and widespread negative consequences for the national economy and major U.S. industrial enterprises, including us and our customers.

If CO_2 and other emission standards are imposed, the standards could require significant increases in capital expenditures and operating costs which would impact the ultimate retirement of older, less-efficient, coal-fired units. While we expect that costs of complying with new CO_2 and other GHG emission standards will be treated like all other reasonable costs of serving customers and should be recoverable from customers as costs of doing business, without such recovery those costs could reduce our future net income and cash flows and harm our financial condition.

Courts adjudicating nuisance and other similar claims against us may order us to limit or reduce our CO_2 emissions. *(Applies to each registrant)*

In 2004, eight states and the City of New York filed an action in Federal District Court for the Southern District of New York against AEP, Cinergy Corp, Xcel Energy, Southern Company and Tennessee Valley Authority. The Natural Resources Defense Council, on behalf of three special interest groups, filed a similar complaint against the same defendants. The actions allege that CO_2 emissions from the defendants' power plants constitute a public nuisance under federal common law due to impacts of global warming, and sought injunctive relief in the form of specific emission reduction commitments from the defendants. The Second Circuit Court of Appeals reinstated this lawsuit on appeal after the lower court had dismissed it. The U.S. Supreme Court has agreed to hear the defendants' request for appeal.

The trial court adjudicating the reinstated nuisance claims may order the defendants, including us, to limit or reduce CO_2 emissions. This or similar remedies could require us to purchase power from third parties to fulfill our commitments to supply power to our customers. This could have a material impact on our costs. While management believes such costs should be recoverable from customers as costs of doing business, without such recovery those costs could reduce our future net income and cash flows and harm our financial condition.

If these or other future actions are resolved against us, substantial modifications of our existing coal-fired power plants could be required. In addition, we could be required to invest significantly in additional emission control equipment, accelerate the timing of capital expenditures, pay penalties and/or halt operations. Moreover, our results of operations and financial position could be reduced due to the timing of recovery of these investments and the expense of ongoing litigation.

We may not fully recover the costs of repairing or replacing damaged equipment in Cook Plant Unit 1 and may be required to pay additional accidental outage insurance proceeds to ratepayers. *(Applies to AEP and I&M)*

Cook Plant Unit 1 is a 1,084 MW nuclear generating unit located in Bridgman, Michigan. In September 2008, I&M shut down Cook Plant Unit 1 (Unit 1) due to turbine vibrations, caused by blade failure, which resulted in significant turbine damage and a small fire on the electric generator. This equipment, located in the turbine building, is separate and isolated from the nuclear reactor. The turbine rotors that caused the vibration were installed in 2006 and were within the vendor's warranty period. The warranty provides for the repair or replacement of the turbine rotors if the damage was caused by a defect in materials or workmanship. Repair of the property damage and replacement of the turbine rotors and other equipment could cost up to approximately $395 million. Management believes that I&M should recover a significant portion of these costs through the turbine vendor's warranty, insurance and the regulatory process. I&M repaired Unit 1 and it resumed operations in December 2009 at slightly reduced power. If the ultimate costs of the incident are not covered by warranty, insurance or through the regulatory process or if any future regulatory proceedings are adverse, it could have an adverse impact on net income, cash flows and financial condition.

Our revenues and results of operations from selling power are subject to market risks that are beyond our control. *(Applies to each registrant.)*

We sell power from our generation facilities into the spot market and other competitive power markets on a contractual basis. We also enter into contracts to purchase and sell electricity, natural gas, emission allowances and coal as part of our power marketing and energy trading operations. With respect to such transactions, the rate of return on our capital investments is not determined through mandated rates, and our revenues and results of operations are likely to depend, in large part, upon prevailing market prices for power in our regional markets and other competitive markets. These market prices can fluctuate substantially over relatively short periods of time. Trading margins may erode as markets mature and there may be diminished opportunities for gain should volatility decline. In addition, the FERC, which has jurisdiction over wholesale power rates, as well as RTOs that oversee some of these markets, may impose price limitations, bidding rules and other mechanisms to address some of the volatility in these markets. Power supply and other similar agreements entered into during extreme market conditions may subsequently be held to be unenforceable by a reviewing court or the FERC. Fuel and emissions prices may also be volatile, and the price we can obtain for power sales may not change at the same rate as changes in fuel and/or emissions costs. These factors could reduce our margins and therefore diminish our revenues and results of operations.

Volatility in market prices for fuel and power may result from:

- weather conditions;
- outages of major generation or transmission facilities;
- seasonality;
- power usage;
- illiquid markets;
- transmission or transportation constraints or inefficiencies;
- availability of competitively priced alternative energy sources;
- demand for energy commodities;
- natural gas, crude oil and refined products, and coal production levels;
- natural disasters, wars, embargoes and other catastrophic events; and
- federal, state and foreign energy and environmental regulation and legislation.

Our power trading (including coal, gas and emission allowances trading and power marketing) and risk management policies cannot eliminate the risk associated with these activities. *(Applies to each registrant.)*

Our power trading (including coal, gas and emission allowances trading and power marketing) activities expose us to risks of commodity price movements. We attempt to manage our exposure by establishing and enforcing risk limits and risk management procedures. These risk limits and risk management procedures may not work as planned and cannot eliminate the risks associated with these activities. As a result, we cannot predict the impact that our energy trading and risk management decisions may have on our business, operating results or financial position.

We routinely have open trading positions in the market, within guidelines we set, resulting from the management of our trading portfolio. To the extent open trading positions exist, fluctuating commodity prices can improve or diminish our financial results and financial position.

Our power trading and risk management activities, including our power sales agreements with counterparties, rely on projections that depend heavily on judgments and assumptions by management of factors such as the future market prices and demand for power and other energy-related commodities. These factors become more difficult to predict and the calculations become less reliable the further into the future these estimates are made. Even when our policies and procedures are followed and decisions are made based on these estimates, results of operations may be diminished if the judgments and assumptions underlying those calculations prove to be inaccurate.

Our financial performance may be adversely affected if we are unable to operate our electric generating facilities successfully. *(Applies to each registrant.)*

Our performance is highly dependent on the successful operation of our electric generating facilities. Operating electric generating facilities involves many risks, including:

- operator error and breakdown or failure of equipment or processes;
- operating limitations that may be imposed by environmental or other regulatory requirements;
- labor disputes;
- fuel supply interruptions caused by transportation constraints, adverse weather, non-performance by our suppliers and other factors; and
- catastrophic events such as fires, earthquakes, explosions, hurricanes, terrorism, floods or other similar occurrences.

A decrease or elimination of revenues from power produced by our electric generating facilities or an increase in the cost of operating the facilities would adversely affect our results of operations.

Parties with whom we have contracts may fail to perform their obligations, which could harm our results of operations. *(Applies to each registrant.)*

We are exposed to the risk that counterparties that owe us money or power could breach their obligations. Should the counterparties to these arrangements fail to perform, we may be forced to enter into alternative hedging arrangements or honor underlying commitments at then-current market prices that may exceed our contractual prices, which would cause our financial results to be diminished and we might incur losses. Although our estimates take into account the expected probability of default by a counterparty, our actual exposure to a default by a counterparty may be greater than the estimates predict.

We rely on electric transmission facilities that we do not own or control. If these facilities do not provide us with adequate transmission capacity, we may not be able to deliver our wholesale electric power to the purchasers of our power. *(Applies to each registrant.)*

We depend on transmission facilities owned and operated by other unaffiliated power companies to deliver the power we sell at wholesale. This dependence exposes us to a variety of risks. If transmission is disrupted, or transmission capacity is inadequate, we may not be able to sell and deliver our wholesale power. If a region's power transmission infrastructure is inadequate, our recovery of wholesale costs and profits may be limited. If restrictive transmission price regulation is imposed, the transmission companies may not have sufficient incentive to invest in expansion of transmission infrastructure.

The FERC has issued electric transmission initiatives that require electric transmission services to be offered unbundled from commodity sales. Although these initiatives are designed to encourage wholesale market transactions for electricity and gas, access to transmission systems may in fact not be available if transmission capacity is insufficient because of physical constraints or because it is contractually unavailable. We also cannot predict whether transmission facilities will be expanded in specific markets to accommodate competitive access to those markets.

We do not fully hedge against price changes in commodities. *(Applies to each registrant.)*

We routinely enter into contracts to purchase and sell electricity, natural gas, coal and emission allowances as part of our power marketing and energy and emission allowances trading operations. In connection with these trading activities, we routinely enter into financial contracts, including futures and options, over-the counter options, financially-settled swaps and other derivative contracts. These activities expose us to risks from price movements. If the values of the financial contracts change in a manner we do not anticipate, it could harm our financial position or reduce the financial contribution of our trading operations.

We manage our exposure by establishing risk limits and entering into contracts to offset some of our positions (i.e., to hedge our exposure to demand, market effects of weather and other changes in commodity prices). However, we do not always hedge the entire exposure of our operations from commodity price volatility. To the extent we do not hedge against commodity price volatility, our results of operations and financial position may be improved or diminished based upon our success in the market.

Financial derivatives reforms could increase the liquidity needs and costs of our commercial trading operations. *(Applies to each registrant.)*

In July 2010, federal legislation was enacted to reform financial markets that significantly alter how over-the-counter (OTC) derivatives are regulated. The law increased regulatory oversight of OTC energy derivatives, including (1) requiring standardized OTC derivatives to be traded on registered exchanges regulated by the Commodity Futures Trading Commission (CFTC), (2) imposing new and potentially higher capital and margin requirements and (3) authorizing the establishment of overall volume and position limits. The law gives the CFTC authority to exempt end users of energy commodities which could reduce, but not eliminate, the applicability of these measures to us and other end users. These requirements could cause our OTC transactions to be more costly and have an adverse effect on our liquidity due to additional capital requirements. In addition, as these reforms aim to standardize OTC products it could limit the effectiveness of our hedging programs because we would have less ability to tailor OTC derivatives to match the precise risk we are seeking to manage.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

GENERATION FACILITIES

UTILITY OPERATIONS

At December 31, 2010, the AEP System owned (or leased where indicated) generating plants, all situated in the states in which our electric utilities serve retail customers, with net power capabilities (winter rating) shown in the following table:

Company	Stations		Coal MW	Natural Gas MW	Nuclear MW	Lignite MW	Hydro MW	Oil MW	Total MW
AEGCo	2	(a)	1,310	1,186					2,496
APCo	17	(b)(c)	5,093	516			677		6,286
CSPCo	7	(d)	2,388	1,347				3	3,738
I&M	9	(a)	2,305		2,191(e)		15		4,511
KPCo	1		1,078						1,078
OPCo	8	(b)(c)	8,482				26		8,508
PSO	8	(f)	1,026	3,554				25	4,605
SWEPCo	11	(g)	1,848	2,668		850			5,366
TNC	6	(f)(h)	377	262				8	647
System Totals	69		23,907	9,533	2,191	850	718	36	37,235
Percentage of System Totals			64.2	25.6	5.9	2.3	1.9	0.1	

(a) Unit 1 of the Rockport Plant is owned one-half by AEGCo and one-half by I&M. Unit 2 of the Rockport Plant is leased one-half by AEGCo and one-half by I&M. The leases terminate in 2022 unless extended.

(b) Unit 3 of the John E. Amos Plant is owned one-third by APCo and two-thirds by OPCo.

(c) APCo owns Units 1 and 3 and OPCo owns Units 2, 4 and 5 of Philip Sporn Plant, respectively.

(d) CSPCo owns generating units in common with Duke Ohio and DP&L. Its percentage ownership interest is reflected in this table.

(e) Cook Unit 1 currently is not operating at the full capacity set forth here. For further information, see *Cook Nuclear Plant* below.

(f) PSO and TNC, along with Oklahoma Municipal Power Authority and The Public Utilities Board of the City of Brownsville, Texas, are joint owners of the Oklaunion power station. PSO and TNC's ownership interest is reflected in this portion of the table. TNC has transferred its interest to a non-utility affiliate through 2027.

(g) SWEPCo owns generating units in common with Cleco Corporation and other unaffiliated parties. Only its ownership interest is reflected in this table.

(h) TNC's gas-fired and oil-fired generation has been deactivated.

Cook Nuclear Plant

The following table provides operating information relating to the Cook Plant.

	Cook Plant	
	Unit 1	**Unit 2**
Year Placed in Operation	1975	1978
Year of Expiration of NRC License	2034	2037
Nominal Net Electrical Rating in Kilowatts	1,084,000	1,107,000
Net Capacity Factors		
2010	82.2%(a)	80.8%
2009	2.8%(a)	83.1%
2008	59.2%(a)	96.6%
2007	97.4%	83.8%

(a) Unit 1 Net Capacity Factor for 2008 through 2010 was impacted by a 2008 forced outage caused by a low pressure turbine blade failure event. The reduced capacity repaired turbine is projected to be replaced with a full capacity turbine in late 2011.

New Generation

SWEPCo is currently constructing the Turk Plant, a new base load 600 MW pulverized coal ultra-supercritical generating unit in Arkansas, which is expected to be in-service in 2012. SWEPCo owns 73% of the Turk Plant and will operate the completed facility. AEGCo is currently constructing the Dresden Plant, a new 580 MW combined-cycle natural gas generating unit in Ohio, which is expected to be in-service in 2012. We resumed work on the Dresden Plant in the first quarter of 2011.

GENERATION AND MARKETING

In addition to the generating facilities described above, AEP has ownership interests in other electrical generating facilities. Information concerning these facilities at December 31, 2010 is listed below.

Facility	Fuel	Location	Capacity Total MW
Desert Sky Wind Farm	Wind	Texas	161
Trent Wind Farm	Wind	Texas	150
Total			311

TRANSMISSION AND DISTRIBUTION FACILITIES

The following table sets forth the total overhead circuit miles of transmission and distribution lines of the AEP System and its operating companies and that portion of the total representing 765kV lines:

	Total Overhead Circuit Miles of Transmission and Distribution Lines	Circuit Miles of 765kV Lines
AEP System (a)	224,703 (b)	2,116
APCo	52,233	734
CSPCo (a)	15,697	—
I&M	22,005	615
KgPCo	1,358	—
KPCo	11,087	258
OPCo	30,754	509
PSO	21,126	—
SWEPCo	21,759	—
TCC	29,686	—
TNC	17,289	—
WPCo	1,708	—

(a) Includes 766 miles of 345,000-volt jointly owned lines.
(b) Includes 73 miles of overhead transmission lines not identified with an operating company.

TRANSMISSION INITIATIVES

We continue our pursuit of transmission opportunities throughout the U.S. In 2009, we announced that our recently formed transmission company, AEP Transmission Company, LLC, will pursue new transmission investments within our retail service territories. Through joint ventures with various other companies, we have existing and/or planned transmission projects and opportunities outside of our retail service territories. We plan to invest approximately $273 million in these projects in 2011. See *Management's Financial Discussion and Analysis* included in the 2010 Annual Reports under the heading *Transmission Initiatives*, for more information.

TITLES

The AEP System's generating facilities are generally located on lands owned in fee simple. The greater portion of the transmission and distribution lines of the System has been constructed over lands of private owners pursuant to easements or along public highways and streets pursuant to appropriate statutory authority. The rights of AEP's public utility subsidiaries in the realty on which their facilities are located are considered adequate for use in the conduct of their business. Minor defects and irregularities customarily found in title to properties of like size and character may exist, but such defects and irregularities do not materially impair the use of the properties affected thereby. AEP's public utility subsidiaries generally have the right of eminent domain which permits them, if necessary, to acquire, perfect or secure titles to or easements on privately held lands used or to be used in their utility operations. Recent legislation in Ohio and Virginia has restricted the right of eminent domain previously granted for power generation purposes.

SYSTEM TRANSMISSION LINES AND FACILITY SITING

Laws in the states of Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Texas, Tennessee, Virginia, and West Virginia require prior approval of sites of generating facilities and/or routes of high-voltage transmission lines. We have experienced delays and additional costs in constructing facilities as a result of proceedings conducted pursuant to such statutes, and in proceedings in which our operating companies have sought to acquire rights-of-way through condemnation. These proceedings may result in additional delays and costs in future years.

CONSTRUCTION PROGRAM

With input from its state utility commissions, the AEP System continuously assesses the adequacy of its generation, transmission, distribution and other facilities to plan and provide for the reliable supply of electric power and energy to its customers. In this assessment process, assumptions are continually being reviewed as new information becomes available, and assessments and plans are modified, as appropriate. AEP forecasts approximately $2.5 billion of construction expenditures for 2011, excluding the debt and equity components of AFUDC and assets acquired under leases. Estimated construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, and the ability to access capital.

CONSTRUCTION EXPENDITURES

The following table shows construction expenditures (including environmental expenditures) during 2008, 2009 and 2010 and a current estimate of 2011 construction expenditures. Actual amounts for 2008, 2009 and 2010 exclude the equity component of AFUDC and assets acquired under leases. Budgeted amounts for 2011 exclude the debt and equity components of AFUDC and assets acquired under leases.

	2008 Actual	2009 Actual	2010 Actual	2011 Estimate (b)
		(in thousands)		
Total AEP System (a)	$3,800,000	$2,792,000	$2,345,000	$2,506,000
APCo	696,767	543,587	534,334	450,100
CSPCo	433,014	302,699	235,901	186,900
I&M	352,335	332,775	333,238	304,900
OPCo	706,315	417,601	276,736	264,100
PSO	285,826	175,122	194,896	169,200
SWEPCo	692,162	596,581	420,485	441,500

(a) Includes expenditures of other subsidiaries not shown. The figures reflect construction expenditures, not investments in subsidiary companies. Excludes discontinued operations.
(b) Excludes Sabine Mining.

The System construction program is reviewed continuously and is revised from time to time in response to changes in estimates of customer demand, business and economic conditions, the cost and availability of capital, environmental requirements and other factors. Changes in construction schedules and costs, and in estimates and projections of needs for additional facilities, as well as variations from currently anticipated levels of net earnings, Federal income and other taxes, and other factors affecting cash requirements, may increase or decrease the estimated capital requirements for the System's construction program.

POTENTIAL UNINSURED LOSSES

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including liabilities relating to damage to our generating plants and costs of replacement power. Unless allowed to be recovered through rates, future losses or liabilities which are not completely insured could have a material adverse effect on results of operations and the financial condition of AEP and other AEP System companies. For risks related to owning a nuclear generating unit, see Note 6 to the consolidated financial statements entitled *Commitments, Guarantees and Contingencies* under the heading *Nuclear Contingencies* for information with respect to nuclear incident liability insurance.

ITEM 3. LEGAL PROCEEDINGS

For a discussion of material legal proceedings, see Note 6 to the consolidated financial statements, entitled *Commitments, Guarantees and Contingencies*, incorporated by reference in Item 8.

ITEM 4. REMOVED AND RESERVED

EXECUTIVE OFFICERS OF THE REGISTRANTS

AEP. The following persons are, or may be deemed, executive officers of AEP. Their ages are given as of February 1, 2011.

Name	Age	Office (a)
Michael G. Morris	64	Chairman of the Board and Chief Executive Officer
Nicholas K. Akins	50	President
Carl L. English	64	Vice Chairman
D. Michael Miller	63	Senior Vice President, General Counsel and Secretary
Robert P. Powers	56	President-AEP Utilities
Brian X. Tierney	43	Executive Vice President and Chief Financial Officer
Susan Tomasky	57	President – AEP Transmission

(a) All of the executive officers have been employed by AEPSC or System companies in various capacities (AEP, as such, has no employees) for the past five years. Mr. Akins became an executive officer of AEP in June 2006, Mr. English in August, 2004, Mr. Miller in July 2010, Mr. Powers in October 2001, Mr. Tierney in January 2008 and Ms. Tomasky in January 2000. All of the above officers are appointed annually for a one-year term by the board of directors of AEP.

APCo, OPCo, PSO and SWEPCo. The names of the executive officers of APCo, OPCo, PSO and SWEPCo, the positions they hold with these companies, their ages as of February 1, 2011, and a brief account of their business experience during the past five years appear below. The directors and executive officers of APCo, OPCo, PSO and SWEPCo are elected annually to serve a one-year term.

Name	Age	Position	Period
Michael G. Morris (a)(b)	64	Chairman of the Board, Chief Executive Officer and Director of AEP	2004-Present
		Chairman of the Board, Chief Executive Officer and Director of APCo, OPCo, PSO and SWEPCo	2004-Present
Nicholas K. Akins (a)	50	President of AEP	2011-Present
		Executive Vice President of AEP, Vice President and Director of APCo, OPCo, PSO and SWEPCo	2006-Present
		President and Chief Operating Officer of SWEPCo	2004-2006
Carl L. English (a)	64	Vice Chairman	2010 - Present
		Chief Operating Officer	2008-2010
		President-AEP Utilities of AEP	2004-2007
		Director and Vice President of APCo, OPCo, PSO and SWEPCo	2004-Present
D. Michael Miller (c)	63	Senior Vice President, General Counsel and Secretary of AEP	2010-Present
		Deputy General Counsel of AEPSC	2002-2010
		Director of APCo, OPCo, PSO and SWEPCo	2010-Present
Robert P. Powers (a)	56	President-AEP Utilities of AEP	2008-Present
		Executive Vice President of AEP	2004-2007
		Director and Vice President of APCo and OPCo	2001-Present
		Director and Vice President of PSO and SWEPCo	2008-Present
Brian X. Tierney (a)	43	Executive Vice President	2008-Present
		Chief Financial Officer	2009-Present
		Director and Vice President of APCo and OPCo	2008-Present

Name	Age	Position	Period
		Director and Vice President of PSO and SWEPCo	2009-Present
		Senior Vice President—Commercial Operations of AEPSC	2005-2007
Susan Tomasky (a)	57	President-AEP Transmission	2008-Present
		Executive Vice President of AEP	2004-Present
		Chief Financial Officer of AEP	2001-2006
		Vice President and Director of APCo, OPCo, PSO and SWEPCo	2000-Present

(a) Messrs. Morris, Akins, English, Powers and Tierney and Ms. Tomasky are directors of CSPCo and I&M.
(b) Mr. Morris is a director of Alcoa, Inc. and The Hartford Financial Services Group, Inc.
(c) Mr. Miller is a director of CSPCo.

The persons listed below are the Presidents, and therefore are also executive officers, of APCo, OPCo, PSO and SWEPCo, respectively.

APCo:

Name	Age	Position	Period
Charles R. Patton	51	President and Chief Operating Officer of APCo	2010-Present
		Executive Vice President of AEP	2009-2010
		Senior Vice President-Regulatory and Public Policy of AEP	2008-2009
		President and Chief Operating Officer of TCC and TNC	2004-2008
		Director and Vice President of PSO and SWEPCo	2009-2010

OPCo:

Name	Age	Position	Period
Joseph Hamrock	47	President and Chief Operating Officer of CSPCo and OPCo	2008-Present
		Senior Vice President and Chief Information Officer of AEPSC	2003-2007

PSO:

Name	Age	Position	Period
Stuart Solomon	49	President and Chief Operating Officer of PSO	2004-Present

SWEPCo:

Name	Age	Position	Period
Venita McCellon-Allen	50	President and Chief Operating Officer of SWEPCo	2010-Present
		Executive Vice President of AEP	2008-2010
		Director and Vice President of APCo and OPCo	2009-2010
		Director and Vice President of PSO and SWEPCo	2008-2009
		President and Chief Operating Officer of SWEPCo	2006-2008
		Senior Vice President-Shared Services of AEPSC	2004-2006
		Director of APCo, OPCo and SWEPCo	2004-2006

PART II

ITEM 5. MARKET FOR REGISTRANTS' COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

AEP. In addition to the discussion below, the remaining information required by this item is incorporated herein by reference to the material under *AEP Common Stock and Dividend Information* and Note 14 to the consolidated financial statements entitled *Financing Activities* under the heading *Dividend Restrictions* in the 2010 Annual Report.

APCo, CSPCo, I&M, OPCo, PSO and SWEPCo. The common stock of these companies is held solely by AEP. The information regarding the amounts of cash dividends on common stock paid by these companies to AEP during 2008, 2009 and 2010 are incorporated by reference to the material under *Statements of Changes in Common Shareholder's Equity and Comprehensive Income (Loss)* and Note 14 to the consolidated financial statements entitled *Financing Activities* under the heading *Dividend Restrictions* in the 2010 Annual Reports.

During the quarter ended December 31, 2010, neither AEP (nor its publicly-traded subsidiaries) purchased equity securities that are registered by AEP (or its publicly-traded subsidiaries) pursuant to Section 12 of the Exchange Act.

ITEM 6. SELECTED FINANCIAL DATA

CSPCo and I&M. Omitted pursuant to Instruction I(2)(a).

AEP, APCo, OPCo, PSO and SWEPCo. The information required by this item is incorporated herein by reference to the material under *Selected Consolidated Financial Data* in the 2010 Annual Reports.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATION

CSPCo and I&M. Omitted pursuant to Instruction I(2)(a). Management's narrative analysis of the results of operations and other information required by Instruction I(2)(a) is incorporated herein by reference to the material under *Management's Financial Discussion and Analysis* in the 2010 Annual Reports.

AEP, APCo, OPCo, PSO and SWEPCo. The information required by this item is incorporated herein by reference to the material under *Management's Financial Discussion and Analysis* in the 2010 Annual Reports.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

AEP, APCo, CSPCo, I&M, OPCo, PSO and SWEPCo. The information required by this item is incorporated herein by reference to the material under *Management's Financial Discussion and Analysis—Quantitative and Qualitative Disclosures about Market and Credit Risk* in the 2010 Annual Reports.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

AEP, APCo, CSPCo, I&M, OPCo, PSO and SWEPCo. The information required by this item is incorporated herein by reference to the financial statements and financial statement schedules described under Item 15 herein.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

AEP, APCo, CSPCo, I&M, OPCo, PSO and SWEPCo. None.

ITEM 9A. CONTROLS AND PROCEDURES

During 2010, management, including the principal executive officer and principal financial officer of each of American Electric Power Company, Inc., Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company (each a "Registrant" and collectively the "Registrants") evaluated each respective Registrant's disclosure controls and procedures. Disclosure controls and procedures are defined as controls and other procedures of the Registrants that are designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act are recorded, processed, summarized and reported within the time periods specified in the Commission's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act is accumulated and communicated to each Registrant's management, including the principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

As of December 31, 2010, these officers concluded that the disclosure controls and procedures in place are effective and provide reasonable assurance that the disclosure controls and procedures accomplished their objectives. The Registrants continually strive to improve their disclosure controls and procedures to enhance the quality of their financial reporting and to maintain dynamic systems that change as events warrant.

There have been no changes in the Registrants' internal control over financial reporting (as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Exchange Act) during the fourth quarter of 2010 that materially affected, or are reasonably likely to materially affect, the Registrants' internal control over financial reporting.

Management is required to assess and report on the effectiveness of its internal control over financial reporting as of December 31, 2010. As a result of that assessment, management determined that there were no material weaknesses as of December 31, 2010 and, therefore, concluded that each Registrant's internal control over financial reporting was effective.

Additional information required by this item of the Registrants is incorporated by reference to *Management's Report on Internal Control over Financial Reporting*, included in the 2010 Annual Report of each Registrant.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

CSPCo and I&M. Omitted pursuant to Instruction I(2)(c).

AEP:

Directors, Director Nomination Process and Audit Committee. Certain of the information called for in this Item 10, including the information relating to directors, is incorporated herein by reference to AEP's definitive proxy information statement (which will be filed with the SEC pursuant to Regulation 14A under the Exchange Act) relating to 2011 Annual Meeting of Shareholders including under the captions "Election of Directors," "Section 16(a) Beneficial Ownership Reporting Compliance," "AEP's Board of Directors and Committees," "Directors," "Involvement by Mr. Hoaglin in Certain Legal Proceedings" and "Shareholder Nominees for Directors."

Executive Officers. Reference also is made to the information under the caption *Executive Officers of the Registrants* in Part I, Item 4 of this report.

Code of Ethics. AEP's Principles of Business Conduct is the code of ethics that applies to AEP's Chief Executive Officer, Chief Financial Officer and principal accounting officer. The Principles of Business Conduct is available on AEP's website at *www.aep.com*. The Principles of Business Conduct will be made available, without charge, in print to any shareholder who requests such document from Investor Relations, American Electric Power Company, Inc., 1 Riverside Plaza, Columbus, Ohio 43215.

If any substantive amendments to the Principles of Business Conduct are made or any waivers are granted, including any implicit waiver, from a provision of the Principles of Business Conduct, to its Chief Executive Officer, Chief Financial Officer or principal accounting officer, AEP will disclose the nature of such amendment or waiver on AEP's website, *www.aep.com*, or in a report on Form 8-K.

Section 16(a) Beneficial Ownership Reporting Compliance. The information required by this item is incorporated herein by reference to information contained in the definitive proxy statement of AEP for the 2011 annual meeting of shareholders.

APCo, OPCo, PSO and SWEPCo:

Directors and Executive Officers. Certain of the information called for in this Item 10, including the information relating to directors, is incorporated herein by reference to the definitive information statement for each company (which will be filed with the SEC under the Exchange Act) relating to 2011 Annual Meeting of Shareholders under the captions "Election of Directors" and "Director Nomination Process."

Audit Committee. Each of APCo, OPCo, PSO and SWEPCo is a controlled subsidiary of AEP and does not have a separate audit committee.

Code of Ethics. AEP's Principles of Business Conduct is the code of ethics that applies to the Chief Executive Officer, Chief Financial Officer and principal accounting officer of APCo, OPCo, PSO and SWEPCo The discussion of AEP's Principles of Business Conduct above is incorporated herein by reference. If any substantive amendments to the Principles of Business Conduct are made or any waivers are granted, including any implicit waiver, from a provision of the Principles of Business Conduct, to the Chief Executive Officer, Chief Financial Officer or principal accounting officer of APCo, OPCo, PSO and SWEPCo, as applicable, that company will disclose the nature of such amendment or waiver on AEP's website, *www.aep.com*, or in a report on Form 8-K.

ITEM 11. EXECUTIVE COMPENSATION

CSPCo and I&M. Omitted pursuant to Instruction I(2)(c).

AEP. The information called for by this Item 11 is incorporated herein by reference to AEP's definitive proxy statement (which will be filed with the SEC pursuant to Regulation 14A under the Exchange Act) relating to the 2011 Annual Meeting including under the captions "Compensation Discussion and Analysis," "Executive Compensation" and "Director Compensation". The information set forth under the subcaption "Human Resources Committee Report" should not be deemed filed nor should it be incorporated by reference into any other filing under the Securities Act of 1933, as amended, or the Exchange Act except to the extent we specifically incorporate such report by reference therein.

APCo, OPCo, PSO and SWEPCO. Certain of the information called for in this Item 11 is incorporated herein by reference to the definitive information statement for each company (which will be filed with the SEC under the Exchange Act) relating to 2011 Annual Meeting of Shareholders including under the captions "Compensation Discussion and Analysis," "Executive Compensation" and "Director Compensation". The information set forth under the subcaption "Human Resources Committee Report" should not be deemed filed nor should it be incorporated by reference into any other filing under the Securities Act of 1933, as amended, or the Exchange Act except to the extent we specifically incorporate such report by reference therein.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

CSPCo and I&M. Omitted pursuant to Instruction I(2)(c).

AEP. The information relating to Security Ownership of Certain Beneficial Owners is incorporated herein by reference to AEP's definitive proxy statement (which will be filed with the SEC pursuant to Regulation 14A under the Exchange Act) relating to 2011 Annual Meeting of Shareholders under the caption "Share Ownership of Certain Beneficial Owners and Management" and "Share Ownership of Directors and Executive Officers".

APCo, OPCo, PSO and SWEPCO. The information relating to Security Ownership of Certain Beneficial Owners is incorporated herein by reference to the definitive information statement for each company (which will be filed with the SEC under the Exchange Act) relating to the 2011 Annual Meeting under the caption "Share Ownership of Certain Beneficial Owners and Management" and "Share Ownership of Directors and Executive Officers".

EQUITY COMPENSATION PLAN INFORMATION

The following table summarizes the ability of AEP to issue common stock pursuant to equity compensation plans as of December 31, 2010:

Plan Category	Number of securities to be issued upon exercise of outstanding options warrants and rights (a)	Weighted average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))(2) (c)
Equity compensation plans approved by security holders(1)	1,557,813	$32.88	18,836,851
Equity compensation plans not approved by security holders	0	0	0
Total	1,557,813	$32.88	18,836,851

(1) Consists of shares to be issued upon exercise of outstanding options granted under the Amended and Restated American Electric Power System Long-Term Incentive Plan.

(2) AEP deducts equity compensation granted in stock units that are paid in cash, rather than AEP common shares, such as AEP's performance units and deferred stock units, from the number of shares available for future grants under the Amended and Restated American Electric Power System Long-Term Incentive Plan. The number of shares available under this plan would be 1,185,633 higher if equity compensation that is paid in cash were not deducted from this column.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

CSPCo and I&M: Omitted pursuant to Instruction I(2)(c).

AEP: The information called for by this Item 13 is incorporated herein by reference to AEP's definitive proxy statement (which will be filed with the SEC pursuant to Regulation 14A under the Exchange Act) relating to the 2011 Annual Meeting under the captions "Transactions with Related Persons" and "Director Independence."

APCo, OPCo, PSO and SWEPCo: **Certain Relationships and Related Transactions.** There were no related person transactions involving APCo, OPCo, PSO or SWEPCo. All of those companies' directors are not independent by virtue of being directors, officers or employees of AEP or APCo, OPCo, PSO or SWEPCo.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

AEP. The information called for by this Item 14 is incorporated herein by reference to AEP's definitive proxy statement (which will be filed with the SEC pursuant to Regulation 14A under the Exchange Act) relating to the 2011 Annual Meeting under the captions "Audit and Non-Audit Fees," "Audit Committee Report" and "Policy on Audit Committee Pre-Approval of Audit and Permissible Non-Audit Services of the Independent Auditor."

APCo, OPCo, PSO and SWEPCo. The information called for by this Item 14 is incorporated herein by reference to the definitive information statement for each company (which will be filed with the SEC under the Exchange Act) relating to the 2011 Annual Meeting under the captions "Independent Registered Public Accounting Firm," and "AEP's Policy on Audit Committee Pre-Approval of Audit and Permissible Non-Audit Services of the Independent Auditor."

CSPCo and I&M.

Each of the above is a wholly-owned subsidiary of AEP and does not have a separate audit committee. A description of the AEP Audit Committee pre-approval policies, which apply to these companies, is contained in the definitive proxy statement of AEP for the 2011 annual meeting of shareholders. The following table presents directly billed fees for professional services rendered by Deloitte & Touche LLP for the audit of these companies' annual financial statements for the years ended December 31, 2009 and 2010, and fees directly billed for other services rendered by Deloitte & Touche LLP during those periods. Deloitte & Touche LLP also provides additional professional and other services to the AEP System, the cost of which may ultimately be allocated to these companies though not billed directly to them. For a description of these fees and services, see the description of principal accounting fees and services for AEP, above.

	CSPCo		I&M	
	2010	2009	2010	2009
Audit Fees	$871,146	$1,038,130	$1,393,624	$1,612,867
Audit-Related Fees	6,500	25,994	6,500	37,851
Tax Fees	9,000	25,536	12,000	39,304
TOTAL	$886,646	$1,089,660	$1,412,124	$1,690,022

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

The following documents are filed as a part of this report:

	Page
1. FINANCIAL STATEMENTS:	
The following financial statements have been incorporated herein by reference pursuant to Item 8.	
AEP and Subsidiary Companies:	
Reports of Independent Registered Public Accounting Firm; Management's Report on Internal Control over Financial Reporting; Consolidated Statements of Income for the years ended December 31, 2010, 2009 and 2008; Consolidated Balance Sheets as of December 31, 2010 and 2009; Consolidated Statements of Cash Flows for the years ended December 31, 2010, 2009 and 2008; Consolidated Statements of Changes in Equity and Comprehensive Income (Loss) for the years ended December 31, 2010, 2009 and 2008; Notes to Consolidated Financial Statements.	
APCo, CSPCo and I&M:	
Consolidated Statements of Income for the years ended December 31, 2010, 2009 and 2008; Consolidated Statements of Changes in Common Shareholder's Equity and Comprehensive Income (Loss) for the years ended December 31, 2010, 2009 and 2008; Consolidated Balance Sheets as of December 31, 2010 and 2009; Consolidated Statements of Cash Flows for the years ended December 31, 2010, 2009 and 2008; Notes to Financial Statements of Registrant Subsidiaries; Report of Independent Registered Public Accounting Firm.	
OPCo and SWEPCo:	
Consolidated Statements of Income for the years ended December 31, 2010, 2009 and 2008; Consolidated Statements of Changes in Equity and Comprehensive Income (Loss) for the years ended December 31, 2010, 2009 and 2008; Consolidated Balance Sheets as of December 31, 2010 and 2009; Consolidated Statements of Cash Flows for the years ended December 31, 2010, 2009 and 2008; Notes to Financial Statements of Registrant Subsidiaries; Report of Independent Registered Public Accounting Firm.	
PSO:	
Statements of Operations for the years ended December 31, 2010, 2009 and 2008; Statements of Changes in Common Shareholder's Equity and Comprehensive Income (Loss) for the years ended December 31, 2010, 2009 and 2008; Balance Sheets as of December 31, 2010 and 2009; Statements of Cash Flows for the years ended December 31, 2010, 2009 and 2008; Notes to Financial Statements of Registrant Subsidiaries; Report of Independent Registered Public Accounting Firm.	
2. FINANCIAL STATEMENT SCHEDULES:	
Financial Statement Schedules are listed in the Index to Financial Statement Schedules (Certain schedules have been omitted because the required information is contained in the notes to financial statements or because such schedules are not required or are not applicable). Reports of Independent Registered Public Accounting Firm	S-1
3. EXHIBITS:	
Exhibits for AEP, APCo, CSPCo, I&M, OPCo, PSO and SWEPCo are listed in the Exhibit Index beginning on page E-1 and are incorporated herein by reference	E-1

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

AMERICAN ELECTRIC POWER COMPANY, INC.

By: /s/ BRIAN X. TIERNEY
(Brian X. Tierney, Executive Vice President and Chief Financial Officer)

Date: February 25, 2011

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
(i) Principal Executive Officer:		
/s/ MICHAEL G. MORRIS **(Michael G. Morris)**	Chairman of the Board, Chief Executive Officer and Director	February 25, 2011
(ii) Principal Financial Officer:		
/s/ BRIAN X. TIERNEY **(Brian X. Tierney)**	Executive Vice President and Chief Financial Officer	February 25, 2011
(iii) Principal Accounting Officer:		
/s/ JOSEPH M. BUONAIUTO **(Joseph M. Buonaiuto)**	Senior Vice President, Controller and Chief Accounting Officer	February 25, 2011
(iv) A Majority of the Directors:		
*E. R. BROOKS *DONALD M. CARLTON * JAMES F. CORDES *RALPH D. CROSBY, JR. *LINDA A. GOODSPEED *THOMAS E. HOAGLIN *LESTER A. HUDSON, JR. *LIONEL L. NOWELL, III *RICHARD L. SANDOR *KATHRYN D. SULLIVAN *SARA MARTINEZ TUCKER *JOHN F. TURNER		
*By: /s/ BRIAN X. TIERNEY **(Brian X. Tierney, Attorney-in-Fact)**		February 25, 2011

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

APPALACHIAN POWER COMPANY
COLUMBUS SOUTHERN POWER COMPANY
OHIO POWER COMPANY
PUBLIC SERVICE COMPANY OF OKLAHOMA
SOUTHWESTERN ELECTRIC POWER COMPANY

By: /s/ BRIAN X. TIERNEY
(Brian X. Tierney, Vice President and Chief Financial Officer)

Date: February 25, 2011

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Signature	Title	Date
(i) Principal Executive Officer:		
/s/ MICHAEL G. MORRIS **(Michael G. Morris)**	Chairman of the Board, Chief Executive Officer and Director	February 25, 2011
(ii) Principal Financial Officer:		
/s/ BRIAN X. TIERNEY **(Brian X. Tierney)**	Vice President, Chief Financial Officer and Director	February 25, 2011
(iii) Principal Accounting Officer:		
/s/ JOSEPH M. BUONAIUTO **(Joseph M. Buonaiuto)**	Controller and Chief Accounting Officer	February 25, 2011
(iv) A Majority of the Directors:		
*NICHOLAS K. AKINS *CARL L. ENGLISH *D. MICHAEL MILLER *ROBERT P. POWERS *BARBARA D. RADOUS *SUSAN TOMASKY *DENNIS E. WELCH		
*By: /s/ BRIAN X. TIERNEY **(Brian X. Tierney, Attorney-in-Fact)**		February 25, 2011

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

INDIANA MICHIGAN POWER COMPANY

By: /s/ BRIAN X. TIERNEY
(Brian X. Tierney Vice President and Chief Financial Officer)

Date: February 25, 2011

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Signature	Title	Date
(i) **Principal Executive Officer:**		
/s/ MICHAEL G. MORRIS **(Michael G. Morris)**	Chairman of the Board, Chief Executive Officer and Director	February 25, 2011
(ii) **Principal Financial Officer:**		
/s/ BRIAN X. TIERNEY **(Brian X. Tierney)**	Vice President, Chief Financial Officer and Director	February 25, 2011
(iii) **Principal Accounting Officer:**		
/s/ JOSEPH M. BUONAIUTO **(Joseph M. Buonaiuto)**	Controller and Chief Accounting Officer	February 25, 2011
(iv) **A Majority of the Directors:**		
*NICHOLAS K. AKINS *SARAH L. BODNER *PAUL CHODAK, III *J. EDWARD EHLER *CARL L. ENGLISH *ALLEN R. GLASSBURN *SCOTT M. KRAWEC *DANIEL V. LEE *MARC E. LEWIS *ROBERT P. POWERS *SUSAN TOMASKY		
*By: /s/ BRIAN X. TIERNEY **(Brian X. Tierney, Attorney-in-Fact)**		February 25, 2011

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INDEX TO FINANCIAL STATEMENT SCHEDULES

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of American Electric Power Company, Inc.:

We have audited the consolidated financial statements of American Electric Power Company, Inc. and subsidiary companies (the "Company") as of December 31, 2010 and 2009, and for each of the three years in the period ended December 31, 2010, and the Company's internal control over financial reporting as of December 31, 2010, and have issued our reports thereon dated February 25, 2011 (which report on the consolidated financial statements expresses an unqualified opinion and includes an explanatory paragraph relating to the adoption of a new accounting pronouncement in 2010); such consolidated financial statements and our reports are included in the Company's 2010 Annual Report (filed as Exhibit 13 to the 2010 Annual Report on Form 10-K of American Electric Power Company, Inc.) and are incorporated herein by reference. Our audits also included the financial statement schedules of the Company listed in Item 15. These financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such consolidated financial statement schedules, when considered in relation to the basic financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 25, 2011

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have audited the financial statements of Appalachian Power Company and subsidiaries, Columbus Southern Power Company and subsidiaries, Indiana Michigan Power Company and subsidiaries, Ohio Power Company Consolidated, Public Service Company of Oklahoma and Southwestern Electric Power Company Consolidated (collectively, the "Companies") as of December 31, 2010 and 2009, and for each of the three years in the period ended December 31, 2010, and have issued our reports thereon dated February 25, 2011 (which report on the financial statements of Southwestern Electric Power Company Consolidated expresses an unqualified opinion and includes an explanatory paragraph relating to the adoption of a new accounting pronouncement in 2010); such financial statements and our reports are included in the Companies' 2010 Annual Reports (filed as Exhibit 13 to the 2010 Annual Reports on Form 10-K of Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company) and are incorporated herein by reference. Our audits also included the financial statement schedules of the Companies listed in Item 15. These financial statement schedules are the responsibility of the Companies' management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedules, when considered in relation to the basic financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 25, 2011

SCHEDULE I
AMERICAN ELECTRIC POWER COMPANY, INC. (Parent)
CONDENSED FINANCIAL INFORMATION
CONDENSED STATEMENTS OF INCOME
For the Years Ended December 31, 2010, 2009 and 2008
(in millions, except per-share and share amounts)

	2010	2009	2008
REVENUES			
Affiliated Revenues	$ 4	$ 2	$ 1
EXPENSES			
Other Operation	54	18	15
OPERATING LOSS	(50)	(16)	(14)
Other Income (Expense):			
Interest Income	22	45	77
Interest Expense	(52)	(84)	(112)
LOSS BEFORE EQUITY EARNINGS	(80)	(55)	(49)
Equity Earnings of Unconsolidated Subsidiaries	1,291	1,412	1,429
NET INCOME	$ 1,211	$ 1,357	$ 1,380
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	479,373,306	458,677,534	402,083,847
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 2.53	$ 2.96	$ 3.43
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	479,601,442	458,982,292	403,640,708
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 2.53	$ 2.96	$ 3.42

See Condensed Notes to Condensed Financial Information.

SCHEDULE I
AMERICAN ELECTRIC POWER COMPANY, INC. (Parent)
CONDENSED FINANCIAL INFORMATION
CONDENSED BALANCE SHEETS
ASSETS
December 31, 2010 and 2009
(in millions)

	2010	2009
CURRENT ASSETS		
Cash and Cash Equivalents	$ 231	$ 233
Other Temporary Investments	99	33
Advances to Affiliates	556	257
Accounts Receivable:		
General	18	27
Affiliated Companies	113	11
Total Accounts Receivable	131	38
Prepayments and Other Current Assets	7	7
TOTAL CURRENT ASSETS	1,024	568
PROPERTY, PLANT AND EQUIPMENT		
General	2	2
Total Property, Plant and Equipment	2	2
Accumulated Depreciation and Amortization	2	2
TOTAL PROPERTY, PLANT AND EQUIPMENT - NET	-	-
OTHER NONCURRENT ASSETS		
Investments in Unconsolidated Subsidiaries	14,297	13,861
Affiliated Notes Receivable	295	575
Deferred Charges and Other Noncurrent Assets	70	70
TOTAL OTHER NONCURRENT ASSETS	14,662	14,506
TOTAL ASSETS	$ 15,686	$ 15,074

See Condensed Notes to Condensed Financial Information.

SCHEDULE I
AMERICAN ELECTRIC POWER COMPANY, INC. (Parent)
CONDENSED FINANCIAL INFORMATION
CONDENSED BALANCE SHEETS
LIABILITIES AND EQUITY
December 31, 2010 and 2009
(dollars in millions)

	2010	2009
CURRENT LIABILITIES		
Advances from Affiliates	$ 295	$ 289
Accounts Payable:		
General	5	-
Affiliated Companies	544	460
Long-term Debt Due Within One Year	-	490
Short Term Debt	650	119
Accrued Interest	2	11
Other Current Liabilities	2	4
TOTAL CURRENT LIABILITIES	1,498	1,373
NONCURRENT LIABILITIES		
Long-term Debt	552	544
Deferred Credits and Other Noncurrent Liabilities	14	17
TOTAL NONCURRENT LIABILITIES	566	561
TOTAL LIABILITIES	2,064	1,934
COMMON SHAREHOLDERS' EQUITY		
Common Stock – Par Value – $6.50 Per Share:		

	2010	2009
Shares Authorized	600,000,000	600,000,000
Shares Issued	501,114,881	498,333,265

	2010	2009
(20,307,725 shares and 20,278,858 shares were held in treasury at December 31, 2010 and 2009, respectively)	3,257	3,239
Paid-in Capital	5,904	5,824
Retained Earnings	4,842	4,451
Accumulated Other Comprehensive Income (Loss)	(381)	(374)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY	13,622	13,140
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 15,686	$ 15,074

See Condensed Notes to Condensed Financial Information.

SCHEDULE I
AMERICAN ELECTRIC POWER COMPANY, INC. (Parent)
CONDENSED FINANCIAL INFORMATION
CONDENSED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2010, 2009 and 2008
(in millions)

	2010	2009	2008
OPERATING ACTIVITIES			
Net Income	$ 1,211	$ 1,357	$ 1,380
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Equity Earnings of Unconsolidated Subsidiaries	(1,291)	(1,412)	(1,429)
Cash Dividend Received from Unconsolidated Subsidiaries	854	530	383
Change in Other Noncurrent Assets	-	5	(3)
Change in Other Noncurrent Liabilities	14	6	44
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	(93)	14	(20)
Accounts Payable	89	29	1
Other Current Assets	-	-	2
Other Current Liabilities	(12)	(3)	(4)
Net Cash Flows from Operating Activities	772	526	354
INVESTING ACTIVITIES			
Purchases of Investment Securities	(333)	(66)	(869)
Sales of Investment Securities	267	36	935
Change in Advances to Affiliates, Net	(299)	1,441	(1,110)
Capital Contributions to Unconsolidated Subsidiaries	(6)	(1,154)	(481)
Issuance of Notes Receivable to Affiliated Companies	(20)	(25)	-
Repayments of Notes Receivable from Affiliated Companies	300	5	5
Other Investing Activities	-	1	-
Net Cash Flows from (Used for) Investing Activities	(91)	238	(1,520)
FINANCING ACTIVITIES			
Issuance of Common Stock, Net	93	1,728	159
Issuance of Long-term Debt	-	-	305
Commercial Paper and Credit Facility Borrowings	466	-	1,969
Change in Short-term Debt, Net	80	119	(659)
Retirement of Long-term Debt	(490)	-	-
Change in Advances from Affiliates, Net	6	(3)	288
Commercial Paper and Credit Facility Repayments	(15)	(1,969)	-
Dividends Paid on Common Stock	(820)	(753)	(660)
Other Financing Activities	(3)	(4)	(1)
Net Cash Flows from (Used for) Financing Activities	(683)	(882)	1,401
Net Increase (Decrease) in Cash and Cash Equivalents	(2)	(118)	235
Cash and Cash Equivalents at Beginning of Period	233	351	116
Cash and Cash Equivalents at End of Period	$ 231	$ 233	$ 351

See Condensed Notes to Condensed Financial Information.

SCHEDULE I
AMERICAN ELECTRIC POWER COMPANY, INC. (Parent)
INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL INFORMATION

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

The condensed financial information of AEP (Parent) is required as a result of the restricted net assets of consolidated subsidiaries exceeding 25% of consolidated net assets as of December 31, 2010. Parent is a public utility holding company that owns all of the outstanding common stock of its public utility subsidiaries and varying percentages of other subsidiaries, including joint ventures and equity investments. The primary source of income for Parent is equity in its subsidiaries' earnings. Its major source of cash is dividends from the subsidiaries. Parent borrows the funds for the money pool that is used by the subsidiaries for their short-term cash needs.

Income Taxes

Parent files a consolidated federal income tax return with its subsidiaries. The AEP System's current consolidated federal income tax is allocated to the AEP System companies so that their current tax expense reflects a separate return result for each company in the consolidated group. The tax benefit of Parent is allocated to its subsidiaries with taxable income.

2. COMMITMENTS, GUARANTEES AND CONTINGENCIES

Parent and its subsidiaries are parties to environmental and other legal matters. For further discussion of commitments, guarantees and contingencies, see Note 6 in the 2010 Annual Reports.

3. FINANCING ACTIVITIES

Long-term Debt

Type of Debt and Maturity	Interest Rate at December 31, 2010	Interest Rate Ranges at December 31, 2010	2009	Outstanding at December 31, 2010	2009
				(in millions)	
Senior Unsecured Notes					
2010-2015	5.25%	5.25%	5.25%-5.375%	$ 243	$ 733
Junior Subordinated Debentures					
2063	8.75%	8.75%	8.75%	315	315
Unamortized Discount (net)				(6)	(14)
Total Long-term Debt Outstanding				552	1,034
Less Portion Due Within One Year				-	490
Long-term Portion				$ 552	$ 544

Long-term debt outstanding at December 31, 2010 is payable as follows:

	2011	2012	2013	2014	2015	After 2015	Total
				(in millions)			
Principal Amount	$ -	$ -	$ -	$ -	$ 243	$ 315	$ 558
Unamortized Discount							(6)
Total Long-term Debt Outstanding at December 31, 2010							$ 552

Short-term Debt

Parent's outstanding short-term debt was as follows:

	December 31,			
	2010		2009	
Type of Debt	Outstanding Amount	Weighted Average Interest Rate	Outstanding Amount	Weighted Average Interest Rate
	(in millions)		(in millions)	
Commercial Paper	$ 650	0.52 %	$ 119	0.26 %
Total Short-term Debt	$ 650		$ 119	

4. RELATED PARTY TRANSACTIONS

Payments on behalf of Subsidiaries

Due to occasional time sensitivity and complexity of payments, Parent makes certain insurance, tax and benefit payments on behalf of subsidiary companies. Parent is then fully reimbursed by the subsidiary companies.

Short-term Lending to Subsidiaries

Parent uses a commercial paper program to meet the short-term borrowing needs of subsidiaries. The program is used to fund both a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds the majority of the nonutility subsidiaries. In addition, the program also funds, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either money pool for regulatory or operational reasons. The program also allows some direct borrowers to invest excess cash with Parent.

Interest expense related to Parent's short-term borrowing is included in Interest Expense on Parent's Statements of Income. Parent incurred interest expense for amounts borrowed from subsidiaries of $1 million, $3 million and $9 million for the years ended December 31, 2010, 2009 and 2008, respectively.

Interest income related to Parent's short-term lending is included in Interest Income on Parent's Statements of Income. Parent earned interest income for amounts advanced to subsidiaries of $2 million, $11 million and $37 million for the years ended December 31, 2010, 2009 and 2008, respectively.

Global Borrowing Notes

Parent issued long-term debt, portions of which were loaned to its subsidiaries. Parent pays interest on the global notes, but the subsidiaries accrue interest for their share of the global borrowing and remit the interest to Parent. Interest income related to Parent's loans to subsidiaries is included in Interest Income on Parent's Statements of Income. Parent earned interest income on loans to subsidiaries of $18 million, $29 million and $28 million for the years ended December 31, 2010, 2009 and 2008, respectively.

SCHEDULE II – VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

AEP

Description	Balance at Beginning of Period	Additions: Charged to Costs and Expenses	Additions: Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2010	$ 37,399	$ 36,699	$ (1,036)	$ 31,507	$ 41,555
Year Ended December 31, 2009	42,388	31,867	(2,850)	34,006	37,399
Year Ended December 31, 2008	52,046	27,598	365	37,621	42,388

(a) Recoveries offset by reclasses to other liabilities.
(b) Uncollectible accounts written off.

APCo

Description	Balance at Beginning of Period	Additions: Charged to Costs and Expenses	Additions: Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2010	$ 5,408	$ 6,573	$ 292	$ 5,606	$ 6,667
Year Ended December 31, 2009	6,176	4,198	(137)	4,829	5,408
Year Ended December 31, 2008	13,948	3,477	289	11,538	6,176

(a) Recoveries offset by reclasses to other liabilities.
(b) Uncollectible accounts written off.

CSPCo

Description	Balance at Beginning of Period	Additions: Charged to Costs and Expenses	Additions: Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2010	$ 3,481	$ 16	$ (404)	$ 1,509	$ 1,584
Year Ended December 31, 2009	2,895	1,362	(775)	1	3,481
Year Ended December 31, 2008	2,563	332	-	-	2,895

(a) Recoveries offset by reclasses to other liabilities.
(b) Uncollectible accounts written off.

I&M

Description	Balance at Beginning of Period	Additions: Charged to Costs and Expenses	Additions: Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2010	$ 2,265	$ (139)(c)	$ (424)	$ 10	$ 1,692
Year Ended December 31, 2009	3,310	78	(783)	340	2,265
Year Ended December 31, 2008	2,711	599	-	-	3,310

(a) Recoveries offset by reclasses to other liabilities.
(b) Uncollectible accounts written off.
(c) Recoveries on previous reserve balance.

OPCo

Description	Balance at Beginning of Period	Additions: Charged to Costs and Expenses	Additions: Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2010	$ 2,665	$ 43	$ (524)	$ -	$ 2,184
Year Ended December 31, 2009	3,586	16	(933)	4	2,665
Year Ended December 31, 2008	3,396	191	-	1	3,586

(a) Recoveries offset by reclasses to other liabilities.
(b) Uncollectible accounts written off.

PSO

Description	Balance at Beginning of Period	Additions: Charged to Costs and Expenses	Additions: Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2010	$ 304	$ 709	$ -	$ 42	$ 971
Year Ended December 31, 2009	20	284	-	-	304
Year Ended December 31, 2008	-	20	-	-	20

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.

SWEPCo

Description	Balance at Beginning of Period	Additions: Charged to Costs and Expenses	Additions: Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2010	$ 64	$ 400	$ 166	$ 42	$ 588
Year Ended December 31, 2009	135	-	-	71	64
Year Ended December 31, 2008	143	-	-	8	135

(a) Recoveries on accounts previously written off.

(b) Uncollectible accounts written off.

EXHIBIT INDEX

The documents listed below are being filed or have previously been filed on behalf of the Registrants shown and are incorporated herein by reference to the documents indicated and made a part hereof. Exhibits ("Ex") not identified as previously filed are filed herewith. Exhibits designated with a dagger (†), are management contracts or compensatory plans or arrangements required to be filed as an Exhibit to this Form. Exhibits designated with an asterisk (*), are filed herewith.

Exhibit Designation	**Nature of Exhibit**	**Previously Filed as Exhibit to:**
REGISTRANT: AEP‡ File No. 1-3525		
3(a)	Composite of the Restated Certificate of Incorporation of AEP, dated April 28, 2009.	2009 Form 10-K, Ex 3(a)
3(b)	Composite By-Laws of AEP, as amended as of April 28, 2009.	2009 Form 10-K, Ex 3(b)
4(a)	Indenture (for unsecured debt securities), dated as of May 1, 2001, between AEP and The Bank of New York, as Trustee.	Registration Statement No. 333-86050, Ex 4(a)(b)(c) Registration Statement No. 333-105532, Ex 4(d)(e)(f)
4(b)	Purchase Agreement dated as of March 8, 2005, between AEP and Merrill Lynch International.	Form 10-Q, Ex 4(a), March 31, 2005
4(c)	Junior Subordinated Indenture dated as of March 1, 2008 between AEP and The Bank of New York as Trustee.	Registration Statement 333-156387, Ex 4(c)(d)
4(d)	Second Amended and Restated $1.5 Billion Credit Agreement, dated as of March 31, 2008, among AEP, the banks, financial institutions and other institutional lenders listed on the signature pages thereof, and JP Morgan Chase Bank, N.A., as Administrative Agent.	Form 10-Q, Ex 10(a) September 30, 2008
4(e)	Second Amended and Restated $1.5 Billion Credit Agreement, dated as of March 31, 2008, among AEP, the banks, financial institutions and other institutional lenders listed on the signature pages thereof, and Barclays Bank plc as Administrative Agent.	Form 10-Q, Ex 10(b) September 30, 2008
4(f)	$650 Million Credit Agreement, dated as of April 4, 2008, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.	Form 10-Q, Ex 10(c) September 30, 2008
4(g)	Amendment, dated as of April 25, 2008, to $650 Million Credit Agreement, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.	Form 10-Q, Ex 10(d) September 30, 2008
4(h)	$350 Million Credit Agreement, dated as of April 4, 2008, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.	Form 10-Q, Ex 10 (e) September 30, 2008
4(i)	Amendment, dated as of April 25, 2008, to $350 Million Credit Agreement, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.	Form 10-Q, Ex 10(f) September 30, 2008
10(a)	Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KPCo, OPCo and I&M and with AEPSC, as amended.	Registration Statement No. 2-52910, Ex 5(a) Registration Statement No. 2-61009, Ex 5(b) 1990 Form 10-K, Ex 10(a)(3)
10(b)	Restated and Amended Operating Agreement, among	Form 10-Q, Ex 10(b), March 31, 2006

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
	PSO, SWEPCo and AEPSC, Issued on February 10, 2006, Effective May 1, 2006.	
10(c)	Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KPCo, OPCo and with AEPSC as agent, as amended.	1985 Form 10-K, Ex 10(b) 1988 Form 10-K, Ex 10(b)(2)
10(d)	Restated and Amended Transmission Coordination Agreement, dated April 15, 2002, among PSO, SWEPCo, TNC and AEPSC.	2009 Form 10-K, Ex 10(d)
10(e)(1)	Amended and Restated Operating Agreement dated as of June 2, 1997, of PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company.	2004 Form 10-K, Ex 10(e)(1)
10(e)(2)	PJM West Reliability Assurance Agreement, dated as of March 14, 2001, among Load Serving Entities in the PJM West service area.	2004 Form 10-K, Ex 10(e)(2)
10(e)(3)	Master Setoff and Netting Agreement among PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company.	2004 Form 10-K, Ex 10(e)(3)
10(f)	Lease Agreements, dated as of December 1, 1989, between AEGCo or I&M and Wilmington Trust Company, as amended.	Registration Statement No. 33-32752, Ex 28(c)(1-6)(C) Registration Statement No. 33-32753, Ex 28(a)(1-6)(C) AEGCo 1993 Form 10-K, Ex 10(c)(1-6)(B) I&M 1993 Form 10-K, Ex 10(e)(1-6)(B)
10(g)	Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KPCo, OPCo and AEPSC.	1996 Form 10-K, Ex 10(l)
10(h)	Consent Decree with U.S. District Court dated October 9, 2007.	Form 8-K, Ex 10.1 dated October 9, 2007
†10(i)	AEP Accident Coverage Insurance Plan for Directors.	1985 Form 10-K, Ex 10(g)
†10(j)	AEP Retainer Deferral Plan for Non-Employee Directors, effective January 1, 2005, as amended February 9, 2007.	2007 Form 10-K, Ex 10(j)(i)
†10(k)	AEP Stock Unit Accumulation Plan for Non-Employee Directors, as amended.	2003 Form 10-K, Ex 10(k)(2)
†10(k)(1)	First Amendment to AEP Stock Unit Accumulation Plan for Non-Employee Directors dated as of February 9, 2007.	2006 Form 10-K, Ex 10(j)(2)(A)
†10(l)	AEP System Excess Benefit Plan, Amended and Restated as of January 1, 2008.	2008 Form 10-K, Ex 10(l)(1)(A)
†10(l)(1)	Guaranty by AEP of AEPSC Excess Benefits Plan.	1990 Form 10-K, Ex 10(h)(1)(B)
*†10(l)(2)	AEP System Supplemental Retirement Savings Plan, Amended and Restated as of January 1, 2011 (Non-Qualified).	
†10(l)(3)	AEPSC Umbrella Trust for Executives.	1993 Form 10-K, Ex 10(g)(3)
†10(l)(3)(A)	First Amendment to AEPSC Umbrella Trust for Executives.	2008 Form 10-K, Ex 10(l)(3)(A)
†10(m)(1)	Employment Agreement between AEP, AEPSC and Michael G. Morris dated December 15, 2003.	2003 Form 10-K, Ex 10(m)(1)
†10(m)(1)(A)	Amendment to Employment Agreement between AEP, AEPSC and Michael G. Morris dated December 9, 2008.	2008 Form 10-K, Ex 10(m)(1)(A)
†10(m)(2)	Memorandum of agreement between Susan Tomasky and AEPSC dated January 3, 2001.	2000 Form 10-K, Ex 10(s)
†10(m)(3)	Employment Agreement dated July 29, 1998 between AEPSC and Robert P. Powers.	2002 Form 10-K, Ex 10(m)(4)
†10(m)(3)(A)	Amendment to Employment Agreement dated December 9, 2008 between AEPSC and Robert P. Powers.	2008 Form 10-K, Ex 10(m)(4)(A)
†10(m)(4)	Letter Agreement dated June 9, 2004 between AEPSC and Carl English.	Form 10-Q, Ex 10(b), September 30, 2004
†10(n)	AEP System Senior Officer Annual Incentive Compensation Plan, amended and restated effective December 13, 2006.	Form 8-K, Ex 10.1 dated April 25, 2007
†10(o)(1)	AEP System Survivor Benefit Plan, effective January 27, 1998.	Form 10-Q, Ex 10, September 30, 1998

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
†10(o)(1)(A)	First Amendment to AEP System Survivor Benefit Plan, as amended and restated effective January 31, 2000.	2002 Form 10-K, Ex 10(o)(2)
†10(o)(1)(B)	Second Amendment to AEP System Survivor Benefit Plan, as amended and restated effective January 1, 2008.	2008 Form 10-K, Ex 10(o)(1)(B)
†10(p)	AEP System Incentive Compensation Deferral Plan Amended and Restated as of January 1, 2008.	2008 Form 10-K, Ex 10(p)
†10(q)	AEP System Nuclear Performance Long Term Incentive Compensation Plan dated August 1, 1998.	2002 Form 10-K, Ex 10(r)
†10(r)	Nuclear Key Contributor Retention Plan Amended and Restated as of January 1, 2008.	2008 Form 10-K, Ex 10(r)
†10(s)	AEP Change In Control Agreement, effective November 1, 2009.	2009 Form 10-K, Ex 10(s)
*†10(t)(1)	Amended and Restated AEP System Long-Term Incentive Plan.	Form 10-Q, Ex 10, March 31, 2010
†10(t)(2)	Form of Performance Share Award Agreement furnished to participants of the AEP System Long-Term Incentive Plan, as amended.	Form 10-Q, Ex 10(c), September 30, 2004
†10(t)(3)	Form of Restricted Stock Unit Agreement furnished to participants of the AEP System Long-Term Incentive Plan, as amended.	Form 10-Q, Ex 10(a), March 31, 2005
†10(t)(3)(A)	Amendment to Form of Restricted Stock Unit Agreement furnished to participants of the AEP System Long-Term Incentive Plan, as amended.	2008 Form 10-K, Ex 10(t)(3)(A)
†10(u)	AEP System Stock Ownership Requirement Plan Amended and Restated Effective January 1, 2010.	2010 Form 10-K, Ex 10(u)
†10(v)	Central and South West System Special Executive Retirement Plan Amended and Restated effective January 1, 2009.	2008 Form 10-K, Ex 10(v)
*12	Statement re: Computation of Ratios.	
*13	Copy of those portions of the AEP 2010 Annual Report (for the fiscal year ended December 31, 2010) which are incorporated by reference in this filing.	
*21	List of subsidiaries of AEP.	
*23	Consent of Deloitte & Touche LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
101.INS	XBRL Instance	
101.SCH	XBRL Taxonomy Extension Schema	
101.CAL	XBRL Taxonomy Extension Calculation	
101.DEF	XBRL Taxonomy Extension Definition	
101.LAB	XBRL Taxonomy Extension Labels	
101.PRE	XBRL Taxonomy Extension Presentation	
REGISTRANT: APCo‡ File No. 1-3457		
3(a)	Composite of the Restated Articles of Incorporation of APCo, amended as of March 7, 1997.	1996 Form 10-K, Ex 3(d)
3(b)	Composite By-Laws of APCo, amended as of February 26, 2008.	2007 Form 10-K, Ex 3(b)
4(a)	Indenture (for unsecured debt securities), dated as of January 1, 1998, between APCo and The Bank of New York, As Trustee.	Registration Statement No. 333-45927, Ex 4(a)(b) Registration Statement No. 333-49071, Ex 4(b) Registration Statement No. 333-84061, Ex 4(b)(c)

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
		Registration Statement No. 333-100451, Ex 4(b)(c)(d) Registration Statement No. 333-116284, Ex 4(b)(c) Registration Statement No. 333-123348, Ex 4(b)(c) Registration Statement No. 333-136432, Ex 4(b)(c)(d) Registration Statement No. 333-161940, Ex 4(b)(c)(d)
4(b)	Company Order and Officer's Certificate to The Bank of New York Mellon, dated May 24, 2010 establishing terms of 3.40% Senior Notes due 2015.	Form 8-K, Ex 4(a) dated May 24, 2010
4(c)	$650 Million Credit Agreement, dated as of April 4, 2008, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.	Form 10-Q, Ex10(c) September 30, 2008
4(d)	Amendment, dated as of April 25, 2008, to $650 Million Credit Agreement, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.	Form 10-Q, Ex 10(d) September 30, 2008
4(e)	$350 Million Credit Agreement, dated as of April 4, 2008, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.	Form 10-Q, Ex 10(e) September 30, 2008
4(f)	Amendment, dated as of April 25, 2008, to $350 Million Credit Agreement, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.	Form 10-Q, Ex 10(f) September 30, 2008
10(a)(1)	Power Agreement, dated October 15, 1952, between OVEC and United States of America, acting by and through the United States Atomic Energy Commission, and, subsequent to January 18, 1975, the Administrator of the Energy Research and Development Administration, as amended.	Registration Statement No. 2-60015, Ex 5(a) Registration Statement No. 2-63234, Ex 5(a)(1)(B) Registration Statement No 2-66301, Ex 5(a)(1)(C) Registration Statement No. 2-67728, Ex 5(a)(1)(D) 1989 Form 10-K, Ex 10(a)(1)(F) 1992 Form 10-K, Ex 10(a)(1)(B)
10(a)(2)	Inter-Company Power Agreement, dated as of July 10, 1953, among OVEC and the Sponsoring Companies, as amended March 13, 2006.	2005 Form 10-K, Ex 10(a)(2)
10(a)(3)	Power Agreement, dated July 10, 1953, between OVEC and Indiana-Kentucky Electric Corporation, as amended.	Registration Statement No. 2-60015, Ex 5(e)
10(b)	Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KPCo, OPCo and I&M and with AEPSC, as amended.	Registration Statement No. 2-52910, Ex 5(a) Registration Statement No. 2-61009, Ex 5(b) 1990 Form 10-K, Ex 10(a)(3), File No. 1-3525
10(c)	Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KPCo, OPCo and with AEPSC as agent, as amended.	1985 Form 10-K, Ex 10(b) 1988 Form 10-K, Ex 10(b)(2)
10(d)(1)	Amended and Restated Operating Agreement of PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company.	2004 Form 10-K, Ex 10(d)(1)
10(d)(2)	PJM West Reliability Assurance Agreement among Load Serving Entities in the PJM West service area.	2004 Form 10-K, Ex 10(d)(2)
10(d)(3)	Master Setoff and Netting Agreement among PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company.	2004 Form 10-K, Ex 10(d)(3)

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
10(e)	Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KPCo, OPCo and AEPSC.	1996 Form 10-K, Ex 10(l), File No. 1-3525
10(f)	Consent Decree with U.S. District Court.	Form 8-K, Ex 10.1 dated October 9, 2007
†10(g)	AEP System Senior Officer Annual Incentive Compensation Plan amended and restated effective December 13, 2006.	Form 8-K, Ex 10.1 dated April 25, 2007
†10(h)(1)	AEP System Excess Benefit Plan, Amended and Restated as of January 1, 2008.	2008 Form 10-K, Ex 10(h)(1)
*†10(h)(2)	AEP System Supplemental Retirement Savings Plan, Amended and Restated as of January 1, 2011 (Non-Qualified).	
†10(h)(3)	AEPSC Umbrella Trust for Executives.	1993 Form 10-K, Ex 10(g)(3), File No. 1-3525
†10(h)(3)(A)	First Amendment to AEPSC Umbrella Trust for Executives.	2008 Form 10-K, Ex 10(h)(3)(A)
†10(i)	Employment Agreement between AEP, AEPSC and Michael G. Morris dated December 15, 2003.	2003 Form 10-K, Ex 10(m)(1)
†10(i)(A)	Amendment to Employment Agreement between AEP, AEPSC and Michael G. Morris dated December 9, 2008.	2008 Form 10-K, Ex 10(i)(A)
†10(i)(2)	Memorandum of Agreement between Susan Tomasky and AEPSC dated January 3, 2001.	2000 Form 10-K, Ex 10(s), File No. 1-3525
†10(i)(3)	Employment Agreement dated July 29, 1998 between AEPSC and Robert P. Powers.	2002 Form 10-K, Ex 10(m)(4)
†10(i)(3)(A)	Amendment to Employment Agreement dated December 9, 2008 between AEPSC and Robert P. Powers.	2008 Form 10-K, Ex 10(i)(4)(A)
†10(i)(4)	Letter Agreement dated June 9, 2004 between AEPSC and Carl English.	Form 10-Q, Ex 10(b), September 30, 2004
†10(j)	AEP System Senior Officer Annual Incentive Compensation Plan, amended and restated effective December 13, 2006.	Form 8-K, Ex 10.1 dated April 25, 2007
†10(k)(1)	AEP System Survivor Benefit Plan, effective January 27, 1998.	Form 10-Q, Ex 10, September 30, 1998
†10(k)(1)(A)	First Amendment to AEP System Survivor Benefit Plan, as amended and restated effective January 31, 2000.	2002 Form 10-K, Ex 10(o)(2)
†10(k)(1)(B)	Second Amendment to AEP System Survivor Benefit Plan, as amended and restated effective January 1, 2008.	2008 Form 10-K, Ex 10(k)(1)(B)
†10(l)	AEP Change In Control Agreement, effective November 1, 2009.	2009 10-K, Ex 10(l)
*†10(m)(1)	Amended and Restated AEP System Long-Term Incentive Plan.	Form 10-Q, Ex 10, March 31, 2010
†10(m)(2)	Form of Performance Share Award Agreement furnished to participants of the AEP System Long-Term Incentive Plan, as amended.	Form 10-Q, Ex 10(c), November 5, 2004
†10(m)(3)	Form of Restricted Stock Unit Agreement furnished to participants of the AEP System Long-Term Incentive Plan, as amended.	Form 10-Q, Ex 10(a), March 31, 2005
†10(m)(3)(A)	Amendment to Form of Restricted Stock Unit Agreement furnished to participants of the AEP System Long-Term Incentive Plan, as amended.	2008 Form 10-K, Ex10(m)(3)(A)
†10(n)	AEP System Stock Ownership Requirement Plan Amended and Restated Effective January 1, 2010.	2009 Form 10-K, Ex 10(n)
†10(o)	Central and South West System Special Executive Retirement Plan Amended and Restated effective January 1, 2009.	2008 Form 10-K, Ex 10(n)
†10(p)	AEP System Incentive Compensation Deferral Plan Amended and Restated as of January 1, 2008.	2008 Form 10-K, Ex 10(o)
†10(q)	AEP System Nuclear Performance Long Term Incentive Compensation Plan dated August 1, 1998.	2002 Form 10-K, Ex 10(r)
†10(r)	Nuclear Key Contributor Retention Plan Amended and Restated as of January 1, 2008.	2008 Form 10-K, Ex 10(q)
*12	Statement re: Computation of Ratios.	

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
*13	Copy of those portions of the APCo 2010 Annual Report (for the fiscal year ended December 31, 2010) which are incorporated by reference in this filing.	
21	List of subsidiaries of APCo.	2006 Form 10-K, Ex 21, File No. 1-3525
*23	Consent of Deloitte & Touche LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
REGISTRANT: CSPCo‡ File No. 1-2680		
3(a)	Composite of Amended Articles of Incorporation of CSPCo, dated May 19, 1994.	1994 Form 10-K, Ex 3(c)
3(b)	Amended Code of Regulations of CSPCo.	Form 10-Q, Ex 3(b) June 30, 2008
4(a)	Indenture (for unsecured debt securities), dated as of September 1, 1997, between CSPCo and Bankers Trust Company, as Trustee.	Registration Statement No. 333-54025, Ex 4(a)(b)(c)(d) Registration Statement No. 333-128174, Ex 4(b)(c)(d) Registration Statement No. 333-150603. Ex 4(b)
4(b)	Indenture (for unsecured debt securities), dated as of February 1, 2003, between CSPCo and Bank One, N.A., as Trustee.	Registration Statement No. 333-128174, Ex 4(e)(f)(g) Registration Statement No. 333-150603 Ex 4(b)
4(c)	Company Order and Officer's Certificate to Deutsche Bank Trust Company Americas, dated May 16, 2008, establishing terms of 6.05% Senior Notes, Series G, due 2018.	Form 8-K, Ex 4(a), dated May 16, 2008
*4(d)	Company Order and Officer's Certificate to Deutsche Bank Trust Company Americas, dated March 16, 2010 establishing terms of floating rate notes Series A due 2012.	Form 8-K, Ex 4(a) dated March 16, 2010
4(e)	$650 Million Credit Agreement, dated as of April 4, 2008, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.	Form 10-Q, Ex 10(c) September 30, 2008
4(f)	Amendment, dated as of April 25, 2008, to $650 Million Credit Agreement, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.	Form 10-Q, Ex 10(d) September 30, 2008
4(g)	$350 Million Credit Agreement, dated as of April 4, 2008, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.	Form 10-Q, Ex 10(e) September 30, 2008
4(h)	Amendment, dated as of April 25, 2008, to $350 Million Credit Agreement, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as	Form 10-Q, Ex 10(f) September 30, 2008

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
	Administrative Agent.	
10(a)(1)	Power Agreement, dated October 15, 1952, between OVEC and United States of America, acting by and through the United States Atomic Energy Commission, and, subsequent to January 18, 1975, the Administrator of the Energy Research and Development Administration, as amended.	Registration Statement No. 2-60015, Ex 5(a) Registration Statement No. 2-63234, Ex 5(a)(1)(B) Registration Statement No. 2-66301, Ex 5(a)(1)(C) Registration Statement No. 2-67728, Ex 5(a)(1)(B) APCo 1989 Form 10-K, Ex 10(a)(1)(F), File No. 1-3457 APCo 1992 Form 10-K, Ex 10(a)(1)(B), File No.1-3457
10(a)(2)	Inter-Company Power Agreement, dated July 10, 1953, among OVEC and the Sponsoring Companies, as amended March 13, 2006.	2005 Form 10-K, Ex 10(a)(2)
10(a)(3)	Power Agreement, dated July 10, 1953, between OVEC and Indiana-Kentucky Electric Corporation, as amended.	Registration Statement No. 2-60015, Ex 5(e)
10(b)(1)	Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KPCo, OPCo and I&M and AEPSC, as amended.	Registration Statement No. 2-52910, Ex 5(a) Registration Statement No. 2-61009, Ex 5(b) 1990 Form 10-K, Ex 10(a)(3), File No. 1-3525
10(b)(2)	Unit Power Agreement, dated March 15, 2007 between AEGCo and CSPCo.	2007 Form 10-K, Ex 10(b)(2)
10(c)	Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KPCo, OPCo, and with AEPSC as agent, as amended.	1985 Form 10-K, Ex 10(b), File No. 1-3525 1988 Form 10-K, Ex 10(b)(2) File No. 1-3525
10(d)(1)	Amended and Restated Operating Agreement of PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company.	2004 Form 10-K, Ex 10(d)(1)
10(d)(2)	PJM West Reliability Assurance Agreement among Load Serving Entities in the PJM West service area.	2004 Form 10-K, Ex 10(d)(2)
10(d)(3)	Master Setoff and Netting Agreement among PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company.	2004 Form 10-K, Ex 10(d)(3)
10(e)	Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KPCo, OPCo and AEPSC.	1996 Form 10-K, Ex 10(l), File No. 1-3525
10(f)	Consent Decree with U.S. District Court.	Form 8-K, Ex 10.1 dated October 9, 2007
*12	Statement re: Computation of Ratios.	
*13	Copy of those portions of the CSPCo 2010 Annual Report (for the fiscal year ended December 31, 2010) which are incorporated by reference in this filing.	
21	List of subsidiaries of CSPCo.	2006 Form 10-K, Ex 21, File No. 1-3525
*23	Consent of Deloitte & Touche LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
REGISTRANT: I&M‡File No. 1-3570		
3(a)	Composite of the Amended Articles of Acceptance of I&M, dated of March 7, 1997.	1996 Form 10-K, Ex 3(c)
3(b)	Composite By-Laws of I&M, amended as of February 26, 2008.	2007 Form 10-K, Ex 3(b)
4(a)	Indenture (for unsecured debt securities), dated as of October 1, 1998, between I&M and The Bank of New York, as Trustee.	Registration Statement No. 333-88523, Ex 4(a)(b)(c) Registration Statement No. 333-58656, Ex 4(b)(c) Registration Statement No. 333-108975, Ex 4(b)(c)(d) Registration Statement No. 333-136538, Ex 4(b)(c) Registration Statement No. 333-156182, Ex 4(b)

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
4(b)	Company Order and Officer's Certificate to The Bank of New York, dated January 15, 2009 establishing terms of 7.00% Senior Notes, Series I due 2019.	Form 8-K, Ex 4(a) dated January 15, 2009
4(c)	$650 Million Credit Agreement, dated as of April 4, 2008, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.	Form 10-Q, Ex.10(c) September 30, 2008
4(d)	Amendment, dated as of April 25, 2008, to $650 Million Credit Agreement, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.	Form 10-Q, Ex.10(d) September 30, 2008
4(e)	$350 Million Credit Agreement, dated as of April 4, 2008, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.	Form 10-Q, Ex.10(e) September 30, 2008
4(f)	Amendment, dated as of April 25, 2008, to $350 Million Credit Agreement, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.	Form 10-Q, Ex.10(f) September 30, 2008
10(a)(1)	Power Agreement, dated October 15, 1952, between OVEC and United States of America, acting by and through the United States Atomic Energy Commission, and, subsequent to January 18, 1975, the Administrator of the Energy Research and Development Administration, as amended.	Registration Statement No. 2-60015, Ex 5(a) Registration Statement No. 2-63234, Ex 5(a)(1)(B) Registration Statement No. 2-66301, Ex 5(a)(1)(C) Registration Statement No. 2-67728, Ex 5(a)(1)(D) APCo 1989 Form 10-K, Ex 10(a)(1)(F), File No. 1-3457 APCo 1992 Form 10-K, Ex 10(a)(1)(B), File No. 1-3457
10(a)(2)	Inter-Company Power Agreement, dated as of July 10, 1953, among OVEC and the Sponsoring Companies, as amended, March 13, 2006.	2005 Form 10-K, Ex 10(a)(2)
10(a)(3)	Power Agreement, dated July 10, 1953, between OVEC and Indiana-Kentucky Electric Corporation, as amended.	Registration Statement No. 2-60015, Ex 5(e)
10(a)(4)	Inter-Company Power Agreement, dated as of July 10, 1953, among OVEC and the Sponsoring Companies, as amended.	Registration Statement No. 2-60015, Ex 5(c) Registration Statement No. 2-67728, Ex 5(a)(3)(B) APCo 1992 Form 10-K, Ex 10(a)(2)(B), File No. 1-3457
10(b)(1)	Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KPCo, I&M, and OPCo and with AEPSC, as amended.	Registration Statement No. 2-52910, Ex 5(a) Registration Statement No. 2-61009, Ex 5(b) 1990 Form 10-K, Ex 10(a)(3), File No. 1-3525
10(b)(2)	Unit Power Agreement dated as of March 31, 1982 between AEGCo and I&M, as amended.	Registration Statement No. 33-32752, Ex 28(b)(1)(A)(B)
10(c)	Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KPCo, OPCo and with AEPSC as agent, as amended.	1985 Form 10-K, Ex 10(b), File No. 1-3525 1988 Form 10-K, File No. 1-3525, Ex 10(b)(2)
10(d)(1)	Amended and Restated Operating Agreement of PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company.	2004 Form 10-K, Ex 10(d)(1)
10(d)(2)	PJM West Reliability Assurance Agreement among Load Serving Entities in the PJM West service area.	2004 Form 10-K, Ex 10(d)(2)
10(d)(3)	Master Setoff and Netting Agreement among PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo,	2004 Form 10-K, Ex 10(d)(3)

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
	Kingsport Power Company and Wheeling Power Company.	
10(e)	Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KPCo, OPCo and AEPSC.	1996 Form 10-K, Ex 10(l), File No. 1-3525
10(f)	Consent Decree with U.S. District Court.	Form 8-K, Ex 10.1 dated October 9, 2007
10(g)	Lease Agreements, dated as of December 1, 1989, between I&M and Wilmington Trust Company, as amended.	Registration Statement No. 33-32753, Ex 28(a)(1-6)(C) 1993 Form 10-K, Ex 10(e)(1-6)(B)
*12	Statement re: Computation of Ratios.	
*13	Copy of those portions of the I&M 2010 Annual Report (for the fiscal year ended December 31, 2010) which are incorporated by reference in this filing.	
21	List of subsidiaries of I&M.	2006 Form 10-K, Ex 21, File No. 1-3525
*23	Consent of Deloitte & Touche LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
REGISTRANT: OPCo‡ File No.1-6543		
3(a)	Composite of the Amended Articles of Incorporation of OPCo, dated June 3, 2002.	Form 10-Q, Ex 3(e), June 30, 2002
3(b)	Amended Code of Regulations of OPCo.	Form 10-Q, Ex 3(b), June 30, 2008
4(a)	Indenture (for unsecured debt securities), dated as of September 1, 1997, between OPCo and Bankers Trust Company (now Deutsche Bank Trust Company Americas), as Trustee.	Registration Statement No. 333-49595, Ex 4(a)(b)(c) Registration Statement No. 333-106242, Ex 4(b)(c)(d) Registration Statement No. 333-75783, Ex 4(b)(c) Registration Statement No. 333-127913, Ex 4(b)(c) Registration Statement No. 333-139802, Ex 4(a)(b)(c) Registration Statement No. 333-139802, Ex 4(b)(c)(d)
4(b)	Company Order and Officer's Certificate to Deutsche Bank Trust Company Americas, dated April 5, 2007, establishing terms of Floating Rate Notes, Series B.	Form 8-K, Ex 4(a) dated April 5, 2007
4(c)	Company Order and Officer's Certificate to Deutsche Bank Trust Company Americas, dated September 24, 2009, establishing terms of 5.375% Senior Notes, Series M due 2021.	Form 8-K, Ex 4(a) dated September 24, 2009
4(d)	Indenture (for unsecured debt securities), dated as of February 1, 2003, between OPCo and Bank One, N.A., as Trustee.	Registration Statement No. 333-127913, Ex 4(d)(e)(f)
4(e)	$650 Million Credit Agreement, dated as of April 4, 2008, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.	Form 10-Q, Ex 10(c) September 30, 2008
4(f)	Amendment, dated as of April 25, 2008, to $650 Million Credit Agreement, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.	Form 10-Q, Ex 10(d) September 30, 2008
4(g)	$350 Million Credit Agreement, dated as of April 4, 2008, among AEP, TCC, TNC, APCo, CSPCo, I&M,	Form 10-Q, Ex 10(e) September 30, 2008

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
	KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.	
4(h)	Amendment, dated as of April 25, 2008, to $350 Million Credit Agreement, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.	Form 10-Q, Ex 10(f) September 30, 2008
10(a)(1)	Power Agreement, dated October 15, 1952, between OVEC and United States of America, acting by and through the United States Atomic Energy Commission, and, subsequent to January 18, 1975, the Administrator of the Energy Research and Development Administration, as amended.	Registration Statement No. 2-60015, Ex 5(a) Registration Statement No. 2-63234, Ex 5(a)(1)(B) Registration Statement No. 2-66301, Ex 5(a)(1)(C) Registration Statement No. 2-67728, Ex 5(a)(1)(D) APCo 1989 Form 10-K, Ex 10(a)(1)(F), File No. 1-3457 APCo 1992 Form 10-K, Ex 10(a)(1)(B), File No. 1-3457
10(a)(2)	Inter-Company Power Agreement, dated July 10, 1953, among OVEC and the Sponsoring Companies, as amended, March 13, 2006.	2005 Form 10-K, Ex 10(a)(2)
10(a)(3)	Power Agreement, dated July 10, 1953, between OVEC and Indiana-Kentucky Electric Corporation, as amended.	Registration Statement No. 2-60015, Ex 5(e)
10(b)	Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KPCo, I&M and OPCo and with AEPSC, as amended.	Registration Statement No. 2-52910, Ex 5(a) Registration Statement No. 2-61009, Ex 5(b) 1990 Form 10-K, Ex 10(a)(3), File 1-3525
10(c)	Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KPCo, OPCo and with AEPSC as agent.	1985 Form 10-K, Ex 10(b), File No. 1-3525 1988 Form 10-K, Ex 10(b)(2), File No. 1-3525
10(d)(1)	Amended and Restated Operating Agreement of PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company.	2004 Form 10-K, Ex 10(d)(1)
10(d)(2)	PJM West Reliability Assurance Agreement among Load Serving Entities in the PJM West service area.	2004 Form 10-K, Ex 10(d)(2)
10(d)(3)	Master Setoff and Netting Agreement among PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, Kingsport Power Company and Wheeling Power Company.	2004 Form 10-K, Ex 10(d)(3)
10(e)	Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KPCo, OPCo and AEPSC.	1996 Form 10-K, Ex 10(l), File No. 1-3525
10(f)	Consent Decree with U.S. District Court.	Form 8-K, Item Ex 10.1 dated October 9, 2007
10(g)(1)	Amendment No. 1, dated October 1, 1973, to Station Agreement dated January 1, 1968, among OPCo, Buckeye and Cardinal Operating Company, and amendments thereto.	1993 Form 10-K, Ex 10(f) 2003 Form 10-K, Ex 10(e)
10(g)(2)	Amendment No. 9, dated July 1, 2003, to Station Agreement dated January 1, 1968, among OPCo, Buckeye and Cardinal Operating Company, and amendments thereto.	Form 10-Q, Ex 10(a), September 30, 2004
†10(h)	AEP System Senior Officer Annual Incentive Compensation Plan amended and restated effective December 13, 2006.	Form 8-K, Ex 10.1 dated April 25, 2007
†10(i)(1)	AEP System Excess Benefit Plan, Amended and Restated as of January 1, 2008.	2008 Form 10-K, Ex 10(j)(1)
*†10(i)(2)	AEP System Supplemental Retirement Savings Plan, Amended and Restated as of January 1, 2011. (Non-Qualified).	
†10(i)(3)	AEPSC Umbrella Trust for Executives.	1993 Form 10-K, Ex 10(g)(3), File No. 1-3525
†10(i)(3)(A)	First Amendment to AEPSC Umbrella Trust for Executives.	2008 Form 10-K, Ex 10(j)(3)(A)

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
†10(j)(1)	Employment Agreement between AEP, AEPSC and Michael G. Morris dated December 15, 2003.	2003 Form 10-K, Ex 10(m)(1)
†10(j)(1)(A)	Amendment to Employment Agreement between AEP, AEPSC and Michael G. Morris dated December 9, 2008.	2008 Form 10-K, Ex 10(k)(1)(A)
†10(j)(2)	Memorandum of agreement between Susan Tomasky and AEPSC dated January 3, 2001.	2000 Form 10-K, Ex 10(s), File No. 1-3525
†10(j)(3)	Employment Agreement dated July 29, 1998 between AEPSC and Robert P. Powers.	2002 Form 10-K, Ex 10(m)(4)
†10(j)(3)(A)	Amendment to Employment Agreement dated December 9, 2008 between AEPSC and Robert P. Powers.	2008 Form 10-K, Ex 10(k)(4)(A)
†10(j)(4)	Letter Agreement dated June 9, 2004 between AEPSC and Carl English.	Form 10-Q, Ex 10(b), September 30, 2004, File No. 1-3525
†10(k)	AEP System Senior Officer Annual Incentive Compensation Plan, amended and restated effective December 13, 2006.	Form 8-K, Ex 10.1 dated April 25, 2007
†10(l)(1)	AEP System Survivor Benefit Plan, effective January 27, 1998.	Form 10-Q, Ex 10, September 30, 1998
†10(l)(1)(A)	First Amendment to AEP System Survivor Benefit Plan, as amended and restated effective January 31, 2000.	2002 Form 10-K, Ex 10(o)(2)
†10(l)(1)(B)	Second Amendment to AEP System Survivor Benefit Plan, as amended and restated effective January 1, 2008.	2008 Form 10-K, Ex 10(m)(1)(B)
†10(m)	AEP Change In Control Agreement, effective November 1, 2009.	2009 Form 10-K, Ex 10(m)
*†10(n)(1)	Amended and Restated AEP System Long-Term Incentive Plan.	Form 10-Q, Ex 10, March 31, 2010
†10(o)	Form of Performance Share Award Agreement furnished to participants of the AEP System Long-Term Incentive Plan, as amended.	Form 10-Q, Ex 10(c), November 5, 2004, File No. 1-3525
†10(p)(1)	Form of Restricted Stock Unit Agreement furnished to participants of the AEP System Long-Term Incentive Plan, as amended.	Form 10-Q, Ex 10(a), March 31, 2005
†10(p)(1)(A)	Amendment to Form of Restricted Stock Unit Agreement furnished to participants of the AEP System Long-Term Incentive Plan, as amended.	2008 Form 10-K, Ex 10(q)(1)(A)
†10(q)	AEP System Stock Ownership Requirement Plan Amended and Restated Effective January 1, 2010.	2009 Form 10-K, Ex 10(q)
†10(r)	Central and South West System Special Executive Retirement Plan Amended and Restated effective January 1, 2009.	2008 Form 10, Ex 10(s)
†10(s)	AEP System Incentive Compensation Deferral Plan Amended and Restated as of January 1, 2008.	2008 Form 10, Ex 10(t)
†10(t)	AEP System Nuclear Performance Long Term Incentive Compensation Plan dated August 1, 1998.	2002 Form 10-K, Ex 10(r)
†10(u)	Nuclear Key Contributor Retention Plan Amended and Restated as of January 1, 2008.	2008 Form 10, Ex 10(v)
*12	Statement re: Computation of Ratios.	
*13	Copy of those portions of the OPCo 2010 Annual Report (for the fiscal year ended December 31, 2010) which are incorporated by reference in this filing.	
21	List of subsidiaries of OPCo.	2006 Form 10-K, Ex 21, File No. 1-3525
*23	Consent of Deloitte & Touche LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
REGISTRANT: PSO‡ File No. 0-343		
3(a)	Certificate of Amendment to Restated Certificate of Incorporation of PSO.	Form 10-Q, Ex 3(a), June 30, 2008
3(b)	Composite By-Laws of PSO amended as of February 26, 2008.	2007 Form 10-K, Ex 3 (b)
4(a)	Indenture (for unsecured debt securities), dated as of November 1, 2000, between PSO and The Bank of New York, as Trustee.	Registration Statement No. 333-100623, Ex 4(a)(b) Registration Statement No. 333-114665, Ex 4(b)(c) Registration Statement No. 333-133548, Ex 4(b)(c) Registration Statement No. 333-156319, Ex 4(b)(c)
4(b)	Eighth Supplemental Indenture, dated as of November 13, 2009 between PSO and The Bank of New York Mellon, as Trustee, establishing terms of the 5.15% Senior Notes, Series H, due 2019.	Form 8-K, Ex 4(a), dated November 13, 2009
4(c)	$650 Million Credit Agreement, dated as of April 4, 2008, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.	Form 10-Q, Ex 10(c) September 30, 2008
4(d)	Amendment, dated as of April 25, 2008, to $650 Million Credit Agreement, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.	Form 10-Q, Ex 10(d) September 30, 2008
4(e)	$350 Million Credit Agreement, dated as of April 4, 2008, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.	Form 10-Q, Ex 10(e) September 30, 2008
4(f)	Amendment, dated as of April 25, 2008, to $350 Million Credit Agreement, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.	Form 10-Q, Ex 10(f) September 30, 2008
10(a)	Restated and Amended Operating Agreement, among PSO, SWEPCo and AEPSC, Issued on February 10, 2006, Effective May 1, 2006.	Form 10-Q, Ex 10(a), March 31, 2006
10(b)	Restated and Amended Transmission Coordination Agreement, dated April 15, 2002, among PSO, SWEPCo, TNC and AEPSC.	2009 Form 10-K Ex 10(b)
†10(c)	AEP System Senior Officer Annual Incentive Compensation Plan amended and restated effective December 13, 2006.	Form 8-K, Ex 10.1 dated April 25, 2007
†10(d)(1)	AEP System Excess Benefit Plan, Amended and Restated as of January 1, 2008.	2008 Form 10-K, Ex 10(d)(1)
*†10(d)(2)	AEP System Supplemental Retirement Savings Plan, Amended and Restated as of January 1, 2011 (Non-Qualified).	
†10(d)(3)	AEPSC Umbrella Trust for Executives.	1993 Form 10-K, Ex 10(g)(3), File No. 1-3525
†10(d)(3)(A)	First Amendment to AEPSC Umbrella Trust for Executives.	2008 Form 10-K, Ex 10(d)(3)(A)
†10(e)(1)	Employment Agreement between AEP, AEPSC and Michael G. Morris dated December 15, 2003.	2003 Form 10-K, Ex 10(m)(1)

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
†10(e)(1)(A)	Amendment to Employment Agreement between AEP, AEPSC and Michael G. Morris dated December 9, 2008.	2008 Form 10-K, Ex 10(e)(A)
†10(e)(2)	Memorandum of Agreement between Susan Tomasky and AEPSC dated January 3, 2001.	2000 Form 10-K, Ex 10(s), File No. 1-3525
†10(e)(3)	Employment Agreement dated July 29, 1998 between AEPSC and Robert P. Powers.	2002 Form 10-K, Ex 10(m)(4)
†10(e)(3)(A)	Amendment to Employment Agreement dated December 9, 2008 between AEPSC and Robert P. Powers.	2008 Form 10-K, Ex 10(e)(4)(A)
†10(e)(4)	Letter Agreement dated June 9, 2004 between AEPSC and Carl English.	Form 10-Q, Ex 10(b), September 30, 2004
†10(f)	AEP System Senior Officer Annual Incentive Compensation Plan, amended and restated effective December 13, 2006.	Form 8-K, Ex 10.1 dated April 25, 2007
†10(g)(1)	AEP System Survivor Benefit Plan, effective January 27, 1998.	Form 10-Q, Ex 10, September 30, 1998
†10(g)(1)(A)	First Amendment to AEP System Survivor Benefit Plan, as amended and restated effective January 31, 2000.	2002 Form 10-K, Ex 10(o)(2)
†10(g)(1)(B)	Second Amendment to AEP System Survivor Benefit Plan, as amended and restated effective January 1, 2008.	2008 Form 10-K, Ex 10(g)(1)(B)
†10(h)	AEP Change In Control Agreement, effective November 1, 2009.	2009 Form 10-K, Ex 10(h)
*†10(i)(1)	Amended and Restated AEP System Long-Term Incentive Plan.	Form 10-Q, Ex 10, March 31, 2010
†10(i)(2)	Form of Performance Share Award Agreement furnished to participants of the AEP System Long-Term Incentive Plan, as amended.	Form 10-Q, Ex 10(c), November 5, 2004
†10(i)(3)	Form of Restricted Stock Unit Agreement furnished to participants of the AEP System Long-Term Incentive Plan, as amended.	Form 10-Q, Ex 10(a), March 31, 2005
†10(i)(3)(A)	Amendment to Form of Restricted Stock Unit Agreement furnished to participants of the AEP System Long-Term Incentive Plan, as amended.	2008 Form 10-K, Ex 10(i)(3)(A)
†10(j)	AEP System Stock Ownership Requirement Plan Amended and Restated Effective January 1, 2010.	2009 Form 10-K, Ex 10(j)
†10(k)	Central and South West System Special Executive Retirement Plan Amended and Restated effective January 1, 2009.	2008 Form 10-K, Ex 10(j)
†10(l)	AEP System Incentive Compensation Deferral Plan Amended and Restated as of January 1, 2008.	2008 Form 10-K, Ex 10(k)
†10(m)	AEP System Nuclear Performance Long Term Incentive Compensation Plan dated August 1, 1998.	2002 Form 10-K, Ex 10(p)
†10(n)	Nuclear Key Contributor Retention Plan Amended and Restated as of January 1, 2008.	2008 Form 10-K, Ex 10(m)
*12	Statement re: Computation of Ratios.	
*13	Copy of those portions of the PSO 2010 Annual Report (for the fiscal year ended December 31, 2010) which are incorporated by reference in this filing.	
21	List of subsidiaries of PSO.	2006 Form 10-K, Ex 21, File No. 1-3525
*23	Consent of Deloitte & Touche LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
REGISTRANT: SWEPCo‡ File No. 1-3146		
3(a)	Composite of Amended Restated Certificate of Incorporation of SWEPCo.	2008 Form 10-K, Ex 3(a)
3(b)	Composite By-Laws of SWEPCo amended as of February 26, 2008.	2007 Form 10-K, Ex 3(b)
4(a)	Indenture (for unsecured debt securities), dated as of February 4, 2000, between SWEPCo and The Bank of New York, as Trustee.	Registration Statement No. 333-96213 Registration Statement No. 333-87834, Ex 4(a)(b) Registration Statement No. 333-100632, Ex 4(b) Registration Statement No. 333-108045, Ex 4(b) Registration Statement No. 333-145669, Ex 4(c)(d) Registration Statement No. 333-161539, Ex 4(b)(c)
4(b)	Eighth Supplemental Indenture dated as of March 1, 2010 between SWEPCo and The Bank of New York Mellon establishing terms of 6.20% Senior Notes, Series H, due 2040.	Form 8-K, Ex 4(a), dated March 8, 2010
4(c)	$650 Million Credit Agreement, dated as of April 4, 2008, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.	Form 10-Q, Ex 10(c) September 30, 2008
4(d)	Amendment, dated as of April 25, 2008, to $650 Million Credit Agreement, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.	Form 10-Q, Ex 10(d) September 30, 2008
4(e)	$350 Million Credit Agreement, dated as of April 4, 2008, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.	Form 10-Q, Ex 10(e) September 30, 2008
4(f)	Amendment, dated as of April 25, 2008, to $350 Million Credit Agreement, among AEP, TCC, TNC, APCo, CSPCo, I&M, KPCo, OPCo, PSO and SWEPCo, the Initial Lenders named therein, the Swingline Bank party thereto, the LC Issuing Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent.	Form 10-Q, Ex 10(f) September 30, 2008
10(a)	Restated and Amended Operating Agreement, among PSO, TCC, TNC, SWEPCo and AEPSC, Issued on February 10, 2006, Effective May 1, 2006.	Form 10-Q, Ex 10(a), March 31, 2006
10(b)	Restated and Amended Transmission Coordination Agreement, dated April 15, 2002, among PSO, SWEPCo, TNC and AEPSC.	Form 2009 10-K, Ex 10(b)
†10(c)	AEP System Senior Officer Annual Incentive Compensation Plan amended and restated effective December 13, 2006.	Form 8-K, Ex 10.1 dated April 25, 2007
†10(d)(1)	AEP System Excess Benefit Plan, Amended and Restated as of January 1, 2008.	2008 Form 10-K, Ex 10(d)(1)
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‡ Certain instruments defining the rights of holders of long-term debt of the registrants included in the financial statements of registrants filed herewith have been omitted because the total amount of securities authorized thereunder does not exceed 10% of the total assets of registrants. The registrants hereby agree to furnish a copy of any such omitted instrument to the SEC upon request.