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1 **I. INTRODUCTION AND EXPERIENCE**

2 **Q 1 PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

3 A 1 William E. Avera, 3907 Red River, Austin, Texas, 78751.

4 **Q 2 IN WHAT CAPACITY ARE YOU EMPLOYED?**

5 A 2 I am the President of FINCAP, Inc., a firm providing financial, economic, and policy
6 consulting services to business and government.

A. Qualifications

7 **Q 3 WHAT ARE YOUR QUALIFICATIONS?**

8 A 3 I received a B.A. degree with a major in economics from Emory University. After
9 serving in the U.S. Navy, I entered the doctoral program in economics at the University
10 of North Carolina at Chapel Hill. Upon receiving my Ph.D., I joined the faculty at the
11 University of North Carolina and taught finance in the Graduate School of Business. I
12 subsequently accepted a position at the University of Texas at Austin where I taught
13 courses in financial management and investment analysis. I then went to work for
14 International Paper Company in New York City as Manager of Financial Education, a
15 position in which I had responsibility for all corporate education programs in finance,
16 accounting, and economics.

17 In 1977, I joined the staff of the Public Utility Commission of Texas (“PUCT”) as
18 Director of the Economic Research Division. During my tenure at the PUCT, I managed
19 a division responsible for financial analysis, cost allocation and rate design, economic
20 and financial research, and data processing systems, and I testified in cases on a variety
21 of financial and economic issues. Since leaving the PUCT in 1979, I have been engaged
22 as a consultant. I have participated in a wide range of assignments involving utility-

1 related matters on behalf of utilities, industrial customers, municipalities, and regulatory
2 commissions. I have previously testified before the Federal Energy Regulatory
3 Commission (“FERC” or “the Commission”), as well as the Federal Communications
4 Commission (“FCC”), the Surface Transportation Board (and its predecessor, the
5 Interstate Commerce Commission), the Canadian Radio-Television and
6 Telecommunications Commission, and regulatory agencies, courts, and legislative
7 committees in over 30 states.

8 In 1995, I was appointed by the PUCT, with the approval of the Governor, to the
9 Synchronous Interconnection Committee to advise the Texas legislature on the costs and
10 benefits of connecting Texas to the national electric transmission grid. In addition, I
11 served as an outside director of Georgia System Operations Corporation, the system
12 operator for electric cooperatives in Georgia.

13 I have served as Lecturer in the Finance Department at the University of Texas at
14 Austin and taught in the evening graduate program at St. Edward’s University for twenty
15 years. In addition, I have lectured on economic and regulatory topics in programs
16 sponsored by universities and industry groups. I have taught in hundreds of educational
17 programs for financial analysts in programs sponsored by the Association for Investment
18 Management and Research, the Financial Analysts Review, and local financial analysts
19 societies. These programs have been presented in Asia, Europe, and North America,
20 including the Financial Analysts Seminar at Northwestern University. I hold the
21 Chartered Financial Analyst (CFA[®]) designation and have served as Vice President for
22 Membership of the Financial Management Association. I have also served on the Board
23 of Directors of the North Carolina Society of Financial Analysts. I was elected Vice

1 Chairman of the National Association of Regulatory Commissioners (“NARUC”)
2 Subcommittee on Economics and appointed to NARUC’s Technical Subcommittee on
3 the National Energy Act. I have also served as an officer of various other professional
4 organizations and societies. A resume containing the details of my experience and
5 qualifications is attached as Exhibit No. AEP-401.

B. Overview

Q 4 WHAT IS THE PURPOSE OF YOUR TESTIMONY?

6 A 4 The purpose of my testimony is to present to the Commission my independent analysis of
7 a fair rate of return on equity (“ROE”) for the jurisdictional transmission operations of
8 Public Service Company of Oklahoma (“PSO”) and Southwestern Electric Power
9 Company (“SWEPCO”), collectively, “the AEP Companies”. My evaluation considered
10 FERC’s established precedent and policy objectives, recent Commission rulemaking,¹
11 industry fundamentals, and independent estimates of the ROE for a benchmark group of
12 electric utilities.
13

Q 5 PLEASE SUMMARIZE THE BASIS OF YOUR KNOWLEDGE AND 14 CONCLUSIONS CONCERNING THE ISSUES TO WHICH YOU ARE 15 TESTIFYING IN THIS CASE. 16

17 A 5 To prepare my testimony, I used information from a variety of sources that would
18 normally be relied upon by a person in my capacity. In connection with the present
19 filing, I considered and relied upon corporate disclosures, publicly available financial
20 reports and filings, and other published information relating to the AEP Companies. In

¹ Promoting Transmission Investment through Pricing Reform, Order No. 679, 116 FERC ¶ 61,057 (July 20, 2006) (“*Order No. 679*”); Order No. 679-A, 117 FERC ¶ 61,327 (Dec. 22, 2006) (“*Order No. 679A*”).

1 addition, I am familiar with FERC policy generally and have submitted testimony in
2 various proceedings at the Commission dealing with required rates of return for
3 transmission facilities, including Docket No. ER00-3316-000 on behalf of American
4 Transmission Company, LLC, Docket No. ER02-485-000 involving the Midwest
5 Independent Transmission System Operator, Inc. (“Midwest ISO”), Docket No. ER03-
6 343-000 on behalf of International Transmission Company, and Docket No. ER04-157-
7 000 on behalf of the transmission-owning members of the ISO New England, Inc. RTO
8 (“New England RTO”). I also reviewed information relating generally to capital markets
9 and specifically to investor perceptions, requirements, and expectations for regulated
10 utilities in a restructured wholesale electric power market. These sources, coupled with
11 my experience in the fields of finance and utility regulation, have given me a working
12 knowledge of ROE issues affecting the AEP Companies and are the basis of my
13 conclusions.

14 **Q 6 WHAT IS THE ROLE OF THE RETURN ON EQUITY IN SETTING A**
15 **UTILITY’S RATES?**

16 A 6 The rate of return on common equity compensates shareholders for the use of their capital
17 to finance the plant and equipment necessary to provide utility service. Investors commit
18 capital only if they expect to earn a return on their investment commensurate with returns
19 available from alternative investments with comparable risks. To be consistent with
20 sound regulatory economics and the standards set forth by the Supreme Court in the
21 Bluefield² and Hope³ cases, a utility’s allowed return on common equity should be
22 sufficient to: (1) fairly compensate capital invested in the utility, (2) enable the utility to

² Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm’n, 262 U.S. 679 (1923).

1 offer a return adequate to attract new capital on reasonable terms, and (3) maintain the
2 utility's financial integrity.

3 **Q 7 HOW DID YOU GO ABOUT DETERMINING A FAIR ROE FOR THE AEP**
4 **COMPANIES?**

5 A 7 I first reviewed the operations and finances of the AEP Companies, as well as the general
6 conditions in the electric utility industry. With this background, I examined current
7 capital market conditions and conducted various quantitative analyses to estimate the
8 current cost of equity. These included the Discounted Cash Flow ("DCF") methodology
9 currently prescribed by this Commission and applied to a proxy group of electric utilities,
10 as well as reference to alternative ROE benchmarks developed using the Capital Asset
11 Pricing Model ("CAPM") and comparable earned rates of return expected for utilities and
12 industrial firms.

C. Summary and Conclusions

13 **Q 8 WHAT IS YOUR CONCLUSION REGARDING THE ROE RANGE OF**
14 **REASONABLENESS FOR THE AEP COMPANIES?**

15 A 8 Based on my capital market analyses and the economic requirements for an electric
16 utility, I recommend an ROE range of reasonableness for the AEP Companies of 7.4
17 percent to 15.4 percent, with a midpoint of 11.4 percent. This ROE range corresponds to
18 the adjusted zone of reasonableness produced by applying the Commission's DCF
19 approach to a proxy group of electric utilities. The reasonableness of my recommended
20 base ROE range for the AEP Companies is also supported by the results of the CAPM
21 and comparable earnings methods and the need to consider flotation costs.

³ Fed. Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944).

1 In evaluating the ROE for jurisdictional transmission operations, it is important to
2 consider the uncertainties associated with the AEP Companies and the challenges that
3 they face – including the financial pressures associated with a substantial capital
4 expansion program. In addition, the allowed ROE for the AEP Companies must reflect
5 the need to provide returns that are sufficient to meet the established policy goal of
6 promoting greater investment in transmission, while recognizing investors’ renewed
7 focus on the associated risks. Taken together, these considerations confirm the
8 reasonableness of my recommended base ROE range for the AEP Companies.

9 **Q 9 WOULD AN ROE ABOVE THE MIDPOINT OF THE PROXY GROUP DCF**
10 **RANGE BE WARRANTED FOR THE AEP COMPANIES?**

11 A 9 Yes. Under established Commission policy, electric utilities, such as the AEP
12 Companies, that transfer operational control of transmission facilities to an independent,
13 regional transmission organization (“RTO”) may request an ROE incentive. Considering
14 the AEP Companies’ participation in a regional planning process and the benefits
15 associated with increased investment in transmission infrastructure, a 50 basis point RTO
16 participation adder is warranted for the AEP Companies.

17 Apart from established Commission policy, consideration of this incentive ROE
18 adder is confirmed by the consensus view of industry stakeholders and investors that
19 higher returns are necessary to overcome the obstacles to new transmission projects. The
20 payoff from facilitating timely investment and stimulating expansion of the transmission
21 infrastructure to further the development of effective competition is so large that the
22 incremental impact of the overall rate of return on the total cost of electricity to
23 consumers pales into insignificance.

1 **II. FUNDAMENTAL ANALYSES**

2 **Q 10 WHAT IS THE PURPOSE OF THIS SECTION?**

3 A 10 As a predicate to my economic and capital market analyses, this section examines
4 conditions in the utility industry generally, and for the AEP Companies specifically, that
5 investors consider in evaluating their required rate of return. An understanding of these
6 fundamental factors, which drive the risks and prospects of the AEP Companies, is
7 essential to develop an informed opinion about investor expectations and requirements
8 that form the basis of a fair ROE.

A. The AEP Companies

9 **Q 11 BRIEFLY DESCRIBE THE AEP COMPANIES AND THEIR ELECTRIC**
10 **UTILITY OPERATIONS.**

11 A 11 PSO and SWEPCO, both wholly-owned subsidiaries of American Electric Power
12 Company, Inc. (“AEP”), are principally engaged in the generation, transmission, and
13 distribution of electric power. PSO provides electric service to approximately 522,000
14 retail customers in eastern and southwestern Oklahoma, as well as selling electric power
15 at wholesale to other utilities, municipalities, and rural electric cooperatives. PSO’s
16 utility facilities include approximately 4,200 megawatts (“MW”) of generating capacity
17 and over 21,000 miles of transmission and distribution lines. Sales to residential
18 customers comprised 39 percent of retail revenues, with 28 percent to commercial, and
19 27 percent to industrial and other end-users. At year-end 2006, PSO had total assets of
20 \$2.6 billion, with total revenues amounting to approximately \$1.4 billion.

21 SWEPCO provides electric utility service to approximately 456,000 retail
22 customers in northeastern Texas, northwestern Louisiana, and western Arkansas. During

1 2006, SWEPCO's revenues totaled approximately \$1.4 billion, with sales to residential,
2 commercial, and industrial and other end-users making up 40 percent, 33 percent, and 27
3 percent of this total, respectively. SWEPCO's generating facilities have a combined
4 capacity of approximately 4,511 MW and its transmission and distribution system
5 includes over 20,600 circuit miles of lines. At year-end 2006, SWEPCO had total assets
6 of \$3.2 billion. Both PSO and SWEPCO are members of the Southwest Power Pool, Inc.
7 ("SPP"), a FERC-approved RTO, and provide transmission service pursuant to the SPP
8 Open Access Transmission Tariff ("OATT").

9 PSO and SWEPCO will require capital investment to meet customer growth,
10 provide for necessary maintenance and replacements of its utility infrastructure, as well
11 as fund new investment in electric generation, transmission and distribution facilities.
12 Combined construction expenditures are anticipated to total approximately \$2.8 billion
13 over the next three years, including environmental expenditures.⁴

14 **Q 12 PLEASE DESCRIBE AEP.**

15 A 12 AEP delivers electricity to more than 5 million customers across 11 states, including
16 Ohio, Indiana, West Virginia, Virginia, Kentucky, Michigan, Tennessee, Oklahoma,
17 Texas, Louisiana, and Arkansas. AEP is one of the largest electric utilities in the U.S.,
18 with its combined utility system including over 35,000 MW of generating capacity and
19 approximately 223,000 miles of transmission and distribution lines. AEP's electric utility
20 subsidiaries rely primarily on coal-fired generation, which makes up approximately 68
21 percent of total system capacity. During 2006, AEP's revenues totaled approximately

⁴ American Electric Power Company, Inc., *2006 Form 10-K Report* at 44.

1 \$12.6 billion, with total assets at year-end of almost \$38.0 billion. AEP's projections call
2 for capital expenditures of approximately \$9.9 billion over the 2007-2009 period.

3 **Q 13 WHERE DO THE AEP COMPANIES OBTAIN THE CAPITAL USED TO**
4 **FINANCE THEIR INVESTMENT IN ELECTRIC UTILITY PLANT?**

5 A 13 As wholly-owned subsidiaries of AEP, PSO and SWEPCO obtain equity capital solely
6 from their parent, whose common stock is publicly traded on the New York Stock
7 Exchange. In addition to capital supplied by AEP, PSO and SWEPCO also issue debt
8 securities directly under their own name.

9 **Q 14 WHAT CREDIT RATINGS ARE ASSIGNED TO THE AEP COMPANIES?**

10 A 14 Currently, PSO and SWEPCO are both assigned a corporate credit rating of "BBB" by
11 Standard & Poor's Corporation ("S&P"). Moody's Investors Service ("Moody's") has
12 assigned an issuer rating of "Baa1" to both utilities, with Fitch Ratings Ltd. ("Fitch")
13 assigning a "BBB+" issuer default rating to PSO and SWEPCO.

14 **Q 15 BRIEFLY DESCRIBE SPP.**

15 A 15 Based in Little Rock, Arkansas, SPP is one of eight regional Reliability Councils and was
16 granted RTO status by FERC in October 2004. SPP administers the OATT and monitors
17 power flow throughout a footprint of over 255,000 square miles that includes over 52,000
18 miles of transmission lines and members in eight states – Arkansas, Kansas, Louisiana,
19 Mississippi, Missouri, New Mexico, Oklahoma, and Texas. The primary objectives of
20 SPP include ensuring open access to bulk electric power lines and maintaining and
21 enhancing transmission system reliability. While SPP has authority for operational
22 control of the system in seven states, the transmission-owning members ("TOs") retain
23 ownership and maintenance responsibility for their transmission assets and perform many

1 operational functions under SPP's direction. SPP's planning process seeks to identify
2 future transmission needs for the region, but the SPP TO's continue to bear the obligation
3 of financing the existing system, as well as providing funds for new construction. As of
4 December 2006, SPP's Transmission Expansion Plan contemplates transmission projects
5 totaling approximately \$1.4 billion, including approximately \$202 million for reliability
6 projects with lead times less than two years.⁵ SPP's regional planning process is
7 described in greater detail in the testimony of Bernard M. Pasternack.

B. Electric Power Industry

8 **Q 16 WHAT GENERAL CONDITIONS HAVE RECENTLY CHARACTERIZED THE**
9 **ELECTRIC POWER INDUSTRY?**

10 A 16 Over the past decade, the industry has experienced significant structural change resulting
11 from market forces and decontrol initiatives. At least initially, this process was largely
12 driven by regulatory reforms at the federal level. The Energy Policy Act of 1992 greatly
13 increased prospective competition for the production and sale of power at the wholesale
14 level, with FERC being a proponent for actions designed to foster greater competition in
15 markets for wholesale power supply.

⁵ *SPP Transmission Expansion Plan*, Southwest Power Pool, approved by the Transmission Working Group (Dec. 11, 2006).

1 In April 1996, this Commission adopted Order No. 888,⁶ which mandated open
2 access to the wholesale transmission facilities of jurisdictional electric utilities. The
3 Commission later addressed improvements to the transmission system, including the
4 establishment of RTOs, in Order No. 2000 and has continued to pursue the goal of
5 creating “seamless” wholesale power markets that facilitate transactions across
6 transmission grid boundaries, among other objectives. More recently, in response to the
7 passage of the Energy Policy Act of 2005, FERC issued its *Order Nos. 679* and *679-A*,
8 establishing incentive-based rate treatments to promote greater capital investment in
9 electric utility infrastructure.

10 **Q 17 WHAT IMPACTS HAVE RECENT EVENTS HAD ON INVESTORS' RISK**
11 **PERCEPTIONS FOR FIRMS INVOLVED IN THE ELECTRIC POWER**
12 **INDUSTRY?**

13 A 17 Events of the last several years caused investors to rethink their assessment of the relative
14 risks associated with the electric power industry. A well-publicized energy crisis in the
15 West wreaked havoc on regional energy markets and had dramatic repercussions for
16 investors and utilities nationwide. Beyond causing state regulators and legislators to re-
17 evaluate industry restructuring plans for the retail sector, the financial implications of the
18 Western experience demonstrated the risks facing the electric power industry.

⁶ Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, 1991-1996 FERC Stats. & Regs., Regs. Preambles ¶ 31,036 (1996), order on reh'g, Order No. 888-A, 1996-2000 FERC Stats. & Regs., Regs. Preambles ¶ 31,048, order on reh'g, Order No. 888-B, 81 FERC ¶ 61,248 (1997), reh'g denied, Order No. 888-C, 82 FERC ¶ 61,046 (1998), aff'd in part and remanded in part sub nom. Transmission Access Policy Study Group v. FERC, 225 F.3d 667 (D.C. Cir. 2000), aff'd sub nom. New York v. FERC, 535 U.S. 1 (2002).

1 **Q 18 WAS THERE A CORRESPONDING IMPACT ON THE INDUSTRY'S CREDIT**
2 **STANDING?**

3 A 18 Yes. The years following the Western power crisis witnessed steady erosion in credit
4 quality throughout the utility industry, both as a result of revised perceptions of the risks
5 in the industry and the weakened finances of the utilities themselves. For example,
6 during 2002, S&P recorded 182 downgrades in the utility industry, versus only fifteen
7 upgrades,⁷ while Moody's downgraded 109 utility issuers and upgraded three.⁸ Credit
8 quality continued to decline during 2003, with S&P reporting that downgrades outpaced
9 upgrades by more than fifteen to one in the fourth quarter of 2003.⁹ S&P reported that
10 the majority of the companies in the utility sector now fall in the triple-B rating category
11 and noted a continued negative bias in the credit outlook.¹⁰

12 **Q 19 IS THE POTENTIAL FOR ENERGY MARKET VOLATILITY AN ONGOING**
13 **CONCERN FOR INVESTORS?**

14 A 19 Most definitely. Investors recognize that the prospect of further turmoil in energy
15 markets cannot be discounted, with S&P reporting continued spikes in wholesale market
16 prices since the Western power crisis.¹¹ Similarly, Fitch recently noted that "elevated
17 energy commodity prices" contribute to a "challenging environment" for electric

⁷ *Id.*

⁸ Moody's Investors Service, *Credit Perspectives* (Jul. 14, 2003) at 33.

⁹ Standard & Poor's Corporation, "U.S. Utilities' Ratings Decline Continued in 2003, But Pace Slows," *RatingsDirect* (Feb. 2, 2004).

¹⁰ Standard & Poor's Corporation, "Few Rating Actions For U.S. Electric, Gas, And Water Utilities In Third Quarter," *RatingsDirect* (Oct. 25, 2006).

¹¹ Standard & Poor's Corporation, "Fuel and Purchased Power Cost Recovery In The Wake Of Volatile Gas And Power Markets – U.S. Electric Utilities To Watch," (Mar. 22, 2006).

1 utilities.¹² Meanwhile, the FERC Staff has continued to recognize the ongoing potential
2 for market disruption in the West, as a 2007 market assessment report concluded:

3 Prices are likely to remain a concern. Last year we monitored transaction
4 above the \$400 per megawatt hour Western soft cap due to scarcity at
5 peak. Given the likelihood of higher-priced natural gas in the West this
6 year, extreme weather could easily raise prices to the peak level again in
7 summer 2007.¹³

8 FERC continues to warn of load pockets vulnerable to periods of high peak demand and
9 unplanned outages of generation or transmission capacity and ongoing reliability
10 concerns led FERC to establish mandatory standards for the bulk power system.¹⁴

11 Additionally, in recent years utilities and their customers have also had to contend
12 with dramatic fluctuations in gas costs due to ongoing price volatility in the spot
13 markets.¹⁵ S&P concluded that “natural gas prices have proven to be very volatile” and
14 warned of a “turbulent journey” due to the uncertainty associated with future fluctuations
15 in energy costs.¹⁶ Fitch also highlighted the challenges that fluctuations in commodity
16 prices can have for utilities and their investors, concluding, “Historically high and

¹² Fitch Ratings, Ltd., “U.S. Power and Gas 2007 Outlook,” *Global Power North American Special Report* (Dec. 15, 2006) at 1.

¹³ Federal Energy Regulatory Commission, Office of Market Oversight and Investigations, “Summer Energy Market Assessment 2007,” (May 17, 2007) at 14.

¹⁴ See *Open Commission Meeting Statement of Chairman Joseph T. Kelliher*, Items E-13: Mandatory Reliability Standards for the Bulk-Power System (Docket No. RM06-16-000) (March 15, 2007).

¹⁵ For example, the Energy Information Administration reported that the average price of gas used by electricity generators (regulated utilities and non-regulated power producers) spiked from an average price of \$7.18 per Mcf for the first eight months of 2005 to over \$11.00 per Mcf in September and October (http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_nus_m.htm).

¹⁶ Standard & Poor’s Corporation, “Top Ten Credit Issues Facing U.S. Utilities,” *RatingsDirect* (Jan. 29, 2007).

1 volatile commodity prices will continue to affect nearly the entire power and gas
2 sector.”¹⁷

3 In addition, while coal has historically been a relatively stable source of fuel,
4 rising prices have raised investors’ concerns. In an article entitled “Rising Coal Prices
5 May Threaten U.S. Utility Credit Profiles,” S&P noted that:

6 More recently, several current and structural developments for the coal
7 mining industry have resulted in a dramatic increase in spot coal prices.¹⁸

8 At the same time, heightened environmental awareness, particularly over carbon and
9 other emissions, has increased exposure to mandated remediation and other compliance
10 costs. The imperative of meeting evolving emissions standards implies significant capital
11 expenditures for those utilities, such as the AEP Companies, that rely significantly on
12 coal-fired generation.

13 **Q 20 HAVE INVESTORS RECOGNIZED THAT ELECTRIC UTILITIES FACE**
14 **ADDITIONAL RISKS BECAUSE OF THE IMPACT OF INDUSTRY**
15 **RESTRUCTURING ON TRANSMISSION OPERATIONS?**

16 A 20 Yes. Policy evolution in the transmission area has been wide reaching and investors’
17 focus on regulatory change in their assessment of risks and prospects was exemplified by
18 S&P:

19 The FERC is in the process of changing every aspect of the electric utility
20 landscape, with industry sages anticipating further transmission and
21 wholesale market development guidance, which could affect the segment's

¹⁷ Fitch Ratings, Ltd., “U.S. Power and Gas 2007 Outlook,” *Global Power North American Special Report* (Dec. 15, 2006) at 1.

¹⁸ Standard & Poor’s Corporation, “Rising Coal Prices May Threaten U.S. Utility Credit Profiles,” *RatingsDirect* (Aug. 12, 2004).

1 credit prospects and quality. ... Uncertainty will exist until operating rules
2 are in place and have stabilized.¹⁹

3 Transmission operations have become increasingly complex and investors have
4 recognized that difficulties in obtaining permits and uncertainty over the adequacy of
5 allowed rates of return have contributed to heightened risk and fueled concerns regarding
6 the adequacy of investment in the transmission sector of the electric power industry.

7 At the same time, the development of competitive wholesale power markets has
8 resulted in increased demand for transmission resources. Concerns regarding the need to
9 encourage further investment in the transmission sector were exemplified by the
10 Commission's observations in *Order No. 679*:

11 [I]nvestment in transmission facilities in real dollar terms declined
12 significantly between 1975 and 1998. Although the amount of investment
13 has increased somewhat in the past few years, data for the most recent
14 year available, 2003, shows investment levels still below the 1975 level in
15 real dollars. This decline in transmission investment in real dollars has
16 occurred while the electric load using the nation's grid more than doubled.
17 Further, the record shows that the growth rate in transmission mileage
18 since 1999 is not sufficient to meet the expected 50 percent growth in
19 consumer demand for electricity over the next two decades.²⁰

20 The challenges posed by an increasingly complex marketplace heighten the uncertainties
21 associated with transmission operations while requiring the commitment of significant
22 new capital investment to maintain and enhance service capabilities. Early on, the U.S.
23 Department of Energy ("DOE") noted the importance of regulatory policies in supporting
24 economic rewards that stimulate investment in new transmission:

25 The economic rewards from improving the transmission system must be
26 greater than the rewards from maintaining the status quo or decreasing the
27 system's ability to reliably support fair and efficient competitive wholesale

¹⁹ Standard & Poor's Corporation, "Electric Transmission at the Starting Gate," *RatingsDirect* (May 10, 2002).

²⁰ *Order No. 679* at P. 10.

1 markets. ...The key to spurring new transmission investment lies in
2 ensuring that the rewards offered by this system of regulation are
3 commensurate with the risks of undertaking these investments and finding
4 innovative approaches to align costs and benefits.²¹

5 **Q 21 CAN YOU DESCRIBE MORE FULLY THE REGULATORY RISKS THAT**
6 **INVESTORS ASSOCIATE WITH TRANSMISSION OPERATIONS?**

7 A 21 Yes. First, investors understand that there is always the potential that regulators will
8 prevent the recovery of the full costs associated with new investment in transmission.
9 They remember the amount of money that was disallowed by regulators through after-
10 the-fact reviews in connection with the construction of generating projects in the 1980s
11 and 1990s, and factor into their expectations the possibility of future cost disallowances.
12 There is no evidence that this exposure has ended with restructuring, and investors have
13 no reason to believe that regulators and intervenors will be less vigorous in pursuing
14 potential disallowances with respect to transmission than they have been in the past with
15 respect to generation projects.

16 Second, investors in transmission take into account the possibility that future
17 regulators might deem long-lived transmission assets to be obsolete because of
18 technological change or competition from alternatives. For example, if distributed
19 generation becomes a major new source of supply, it may reduce the need for existing
20 transmission assets. Thus, investors perceive a long-term risk in the potential for
21 stranded costs associated with transmission.

22 Third, investors recognize that there are federal-state jurisdictional issues
23 involving transmission, and that even if the Commission permits the costs of transmission
24 to be recovered through FERC rates, there is no assurance that utilities will be able to

²¹ U.S. Department of Energy, *National Transmission Grid Study* (May 2002).

1 obtain full and timely recovery of these costs from retail customers, which is where the
2 majority of the money must come from to repay the AEP Companies and the other SPP
3 TOs. Investors believe that operating a capital intensive business in a regulatory “no-
4 man’s land” created by multiple jurisdictions means higher risk; a consideration that is
5 not lost on potential investors as the SPP TOs undertake the capital investment program
6 contemplated under SPP’s expansion plan.

7 Finally, investors recognize that utilities incur substantial up front costs to design
8 transmission projects and then obtain siting approvals for them, and that regulators or
9 customer groups may try to deny these utilities recovery of the associated costs if the
10 projects are unable to obtain the required approvals. The investment community
11 understands that regulation can lead to a significant lag between the time an investment is
12 made and when the costs are reflected in rates and these up front capital costs may be tied
13 up without earning an actual return for several years before the outcome of siting issues
14 are decided.

15 Virtually all industry stakeholders have recognized that regulatory uncertainties
16 increase the risks associated with the utility industry. For example, the DOE identified
17 “reducing regulatory uncertainty” as critical in stimulating increased investment in the
18 power industry and has noted that lack of clarity in the regulatory structure was inhibiting
19 planning and investment.²²

20 **Q 22 IS THERE ANY INDICATION THAT THESE UNCERTAINTIES HAVE**
21 **IMPACTED INVESTORS’ WILLINGNESS TO SUPPLY CAPITAL?**

²² U.S. Department of Energy, *National Transmission Grid Study* (May 2002), at 24 and 31.

1 A 22 Yes. As early as 2003, the *Wall Street Journal* cited the debilitating impact of an
2 “unsteady regulatory environment” and the “chaotic combination of regulated and
3 deregulated markets” in explaining inhibitions to increased investment in the electric
4 utility system.²³ Similarly, S&P warned investors that the partial reforms presently
5 characterizing wholesale power markets invite dysfunction and that elevated risks will
6 discourage new capital, “or at least make it more expensive.” S&P observed:

7 Investors should not expect that such risk will dissipate any time soon.
8 Instead, credit risk could actually intensify if the politically charged debate
9 over reform continues for years, as it might very well do. And even if
10 policy makers succeed in crafting a comprehensive solution to the
11 problems of the nation’s energy grid, the regulatory treatment of the costs
12 needed to upgrade the infrastructure remains uncertain.²⁴

13 In an article sponsored by the electric industry that appeared in *Forbes Magazine*,
14 a number of investment analysts confirmed that investors perceive significant risks
15 associated with investing in transmission in the United States.²⁵ For example, Jeffery R.
16 Holzschuh, the Managing Director of Morgan Stanley’s Global Power Group, confirmed
17 that the investment community recognizes that the returns permitted by FERC-approved
18 rates act as a ceiling on the actual returns investors can expect and that there are serious
19 regulatory risks that make cost recovery uncertain. As he summarized, “[t]here is a cap
20 on how much I can earn and no floor on how much I can lose.”²⁶ More recently,
21 continued concerns over the need to overcome these uncertainties and promote greater

²³ Smith, Rebecca, “Overloaded Circuits Blackout Signals Major Weakness in U.S. Power Grid,” *The Wall Street Journal* (Aug. 18, 2003).

²⁴ Standard & Poor’s Corporation, “Electric Utility Blackout Puts Spotlight on Political and Regulatory Credit Risk,” *RatingsDirect* (Aug. 21, 2003).

²⁵ “Electric Utilities: Creating the Right Environment For Transmission Investment,” *Forbes Magazine* (Sep. 20, 2004).

²⁶ *Id.* at 58.

1 investment in transmission infrastructure led to the Commission's *Order No. 679*, which
2 represents another evolution in the Commission's efforts to expand transmission
3 capacity.

4 **Q 23 WHAT IS THE PURPOSE OF THE COMMISSION'S ORDERS IN DOCKET NO.**
5 **RM06-4-001?**

6 A 23 *Order Nos. 679* and *679-A* address the requirements of the Energy Policy Act of 2005,
7 which calls for the establishment of incentive-based rate treatments to achieve greater
8 grid reliability and lower-cost electric power for customers by encouraging transmission
9 infrastructure investment. The Commission's rulings recognize the legislative mandate to
10 promote capital investment, in light of the substantial challenges faced by utilities in
11 constructing new transmission projects. In response to this mandate, and after
12 considering stakeholder comments, FERC provides utilities with the opportunity to seek
13 various incentive rate treatments.

14 **III. CAPITAL MARKET ESTIMATES**

15 **Q 24 WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?**

16 A 24 In this section, capital market estimates of the cost of equity are developed for a proxy
17 group of electric utilities. First, I discuss the concept of the cost of equity, along with the
18 risk-return tradeoff principle fundamental to capital markets. Next, I describe DCF
19 analyses conducted to estimate the current cost of equity for the reference group of
20 electric utilities. Finally, I present alternative ROE benchmarks developed using the
21 CAPM and comparable earnings approaches.

A. Cost of Equity Concept

1 **Q 25 WHAT ROLE DOES THE RETURN ON COMMON EQUITY PLAY IN A**
2 **UTILITY'S RATES?**

3 A 25 The return on common equity is the cost of inducing and retaining investment in the
4 utility's physical plant and assets. This investment is necessary to finance the asset base
5 needed to provide utility service. Competition for investor funds is intense and investors
6 are free to invest their funds wherever they choose. They will commit money to a
7 particular investment only if they expect it to produce a return commensurate with those
8 from other investments with comparable risks.

9 **Q 26 WHAT FUNDAMENTAL ECONOMIC PRINCIPLE UNDERLIES THIS COST**
10 **OF EQUITY CONCEPT?**

11 A 26 The fundamental economic principle underlying the cost of equity concept is the notion
12 that investors are risk averse. In capital markets where relatively risk-free assets are
13 available (*e.g.*, U.S. Treasury securities), investors can be induced to hold riskier assets
14 only if they are offered a premium, or additional return, above the rate of return on a risk-
15 free asset. Since all assets compete with each other for investor funds, riskier assets must
16 yield a higher expected rate of return than safer assets to induce investors to hold them.

17 Given this risk-return tradeoff, the required rate of return (k) from an asset (i) can
18 generally be expressed as

19
$$K_i = R_f + RP_i$$

20 where: R_f = risk-free rate of return, and
21 RP_i = Risk premium required to hold riskier asset i .

1 Thus, the required rate of return for a particular asset at any time is a function of: (1) the
2 yield on risk-free assets and (2) its relative risk, with investors demanding
3 correspondingly larger risk premiums for assets bearing greater risk.

4 **Q 27 IS THERE EVIDENCE THAT THE RISK-RETURN TRADEOFF PRINCIPLE**
5 **ACTUALLY OPERATES IN THE CAPITAL MARKETS?**

6 A 27 Yes. The risk-return tradeoff can be readily documented in segments of the capital
7 markets where required rates of return can be directly inferred from market data and
8 where generally accepted measures of risk exist. Bond yields, for example, reflect
9 investors' expected rates of return, and bond ratings measure the risk of individual bond
10 issues. The observed yields on government securities, which are considered free of
11 default risk, and bonds of various rating categories demonstrate that the risk-return
12 tradeoff does, in fact, exist in the capital markets.

13 **Q 28 DOES THE RISK-RETURN TRADEOFF OBSERVED WITH FIXED INCOME**
14 **SECURITIES EXTEND TO COMMON STOCKS AND OTHER ASSETS?**

15 A 28 It is generally accepted that the risk-return tradeoff evidenced with long-term debt
16 extends to all assets. Documenting the risk-return tradeoff for assets other than fixed
17 income securities, however, is complicated by two factors. First, there is no standard
18 measure of risk applicable to all assets. Second, for most assets – including common
19 stock – required rates of return cannot be directly observed. Yet there is every reason to
20 believe that investors exhibit risk aversion in deciding whether or not to hold common
21 stocks and other assets, just as when choosing among fixed-income securities.

22 **Q 29 IS THIS RISK-RETURN TRADEOFF LIMITED TO DIFFERENCES BETWEEN**
23 **FIRMS?**

1 A 29 No. The risk-return tradeoff principle applies not only to investments in different firms,
2 but also to different securities issued by the same firm. The securities issued by a utility
3 vary considerably in risk because they have different characteristics and priorities. Long-
4 term debt secured by a mortgage on property is senior among all capital in its claim on a
5 utility's net revenues and is, therefore, the least risky. Following first mortgage bonds
6 are other debt instruments also holding contractual claims on the utility's net revenues,
7 such as subordinated debentures. The last investors in line are common shareholders.
8 They receive only the net revenues, if any, that remain after all other claimants have been
9 paid. As a result, the rate of return that investors require from a utility's common stock,
10 the most junior and riskiest of its securities, must be considerably higher than the yield
11 offered by the utility's senior, long-term debt.

12 **Q 30 WHAT DOES THE ABOVE DISCUSSION IMPLY WITH RESPECT TO**
13 **ESTIMATING THE COST OF EQUITY?**

14 A 30 Although the cost of equity cannot be observed directly, it is a function of the returns
15 available from other investment alternatives and the risks to which the equity capital is
16 exposed. Because it is unobservable, the cost of equity for a particular utility must be
17 estimated by analyzing information about capital market conditions generally, assessing
18 the relative risks of the company specifically, and employing various quantitative
19 methods that focus on investors' required rates of return. These various quantitative
20 methods typically attempt to infer investors' required rates of return from stock prices,
21 interest rates, or other capital market data.

22 **Q 31 WHAT METHOD DID YOU USE TO EVALUATE THE COST OF EQUITY FOR**
23 **THE AEP COMPANIES?**

1 A 31 In deference to FERC precedent, my recommendations were based on the results of the
2 Commission's one-step DCF methodology for electric utilities.²⁷ In recognition of the
3 fact that no single approach to estimating a utility's cost of equity can be regarded as
4 wholly reliable, I also developed alternative ROE benchmarks using forward-looking
5 applications of the CAPM and comparable earnings approaches. As the Federal
6 Communications Commission recognized:

7 Equity prices are established in highly volatile and uncertain capital
8 markets... Different forecasting methodologies compete with each other
9 for eminence, only to be superseded by other methodologies as conditions
10 change... In these circumstances, we should not restrict ourselves to one
11 methodology, or even a series of methodologies, that would be applied
12 mechanically. Instead, we conclude that we should adopt a more
13 accommodating and flexible position.²⁸

14 Similarly, FERC has also recognized that it may be appropriate to consider the
15 results of alternative methods. For example, the Commission concluded in *Distrigas of*
16 *Massachusetts Corp.* that "no one methodology is preferred to the exclusion of all others.
17 The DCF methodology, which we endorse, is but one analytical tool."²⁹ FERC has also
18 granted that "[i]n some instances, the DCF methodology alone may be inappropriate."³⁰
19 More recently, while electing not to make "broadly applicable changes to how the
20 Commission has traditionally performed its DCF analysis," *Order No. 679* noted the

²⁷ See, e.g., Bangor Hydro Electric Company, Opinion No. 489, 117 FERC 61,129 (2006) ("*ISO New England*"); Midwest Independent Transmission System Operator, Inc., Order Affirming Initial Decision, With Modification, 100 FERC ¶ 61,292 (2002); Southern California Edison Co., Opinion No. 445, 92 FERC ¶ 61,070 (2000) ("*Southern California Edison*").

²⁸ Federal Communications Commission, Report and Order 42-43, CC Docket No. 92-133 (1995).

²⁹ *Distrigas of Massachusetts Corp.*, 41 FERC ¶ 61,205 at 61,550 (1987), modified on reh'g, 42 FERC ¶ 61,225 (1988).

³⁰ *Williston Basin Interstate Pipeline Co.*, 50 FERC ¶ 61,284 at 61,913 n.90 (1990), vacated on other grounds, 931 F.2d 949 (D.C. Cir. 1991).

1 opinion that “there is a benefit to introducing more information into the analysis process,”
2 and indicated FERC’s willingness to consider modification to its standard approach on a
3 case-by-case basis.³¹

4 Therefore, I also evaluated a fair rate of return using a forward-looking
5 application of the CAPM method, as well as a comparable earnings approach based on
6 investors’ current expectations in the capital markets. In my opinion, comparing
7 estimates produced by one method with those produced by other approaches ensures that
8 estimates of the cost of equity pass fundamental tests of reasonableness and economic
9 logic.

B. DCF Model

10 **Q 32 HOW DID YOU IMPLEMENT THE COMMISSION’S DCF MODEL TO**
11 **ESTIMATE THE COST OF EQUITY FOR THE AEP COMPANIES?**

12 A 32 As described above, application of the DCF model to estimate the cost of equity requires
13 an observable stock price. Because PSO and SWEPCO are wholly-owned subsidiaries of
14 AEP and have no publicly traded stock, the cost of equity for these utilities cannot be
15 estimated directly using the DCF model. As an alternative, the cost of equity for an
16 untraded firm is often estimated by applying the DCF model to publicly traded
17 companies engaged in similar business activities.

18 The formula rates proposed by the AEP Companies apply to transmission
19 facilities operated within the scope of SPP. In order to reflect the risks and prospects
20 associated with the AEP Companies’ jurisdictional utility operations, my analyses
21 focused on a group of twenty-four transmission-owning utilities located in SPP and

³¹ Order No. 679 at P. 102.

1 adjacent RTOs (“Proxy TOs”). Following the same general approach approved by the
2 Commission in *New England RTO*, these companies consisted of the transmission-
3 owning members of SPP, the Midwest ISO, and the PJM Interconnection, LLC (“PJM”)
4 with publicly traded stock. Excluded from my analyses were firms that do not pay
5 common dividends or for which no I/B/E/S International, Inc. (“IBES”) growth rate or
6 Value Line data was currently available, as well as one firm (Duquesne Light Holdings)
7 that has agreed to be acquired by a private investment group. In addition, consistent with
8 the Commission’s findings in *New England RTO*, UGI Corporation was also eliminated
9 from the proxy group.

10 Consistent with FERC’s recent guidance, this proxy group is composed of utilities
11 “with a direct correlation” to SPP and “the broader RTO markets” with which SPP
12 interacts.³² The average S&P corporate credit rating for the Proxy TO group is BBB+,
13 which is comparable to the “Baa1” and “BBB” ratings assigned to PSO and SWEPCO by
14 Moody’s and S&P, respectively. Like the AEP Companies and the other SPP members,
15 the Midwest ISO and PJM utilities operate in markets where an effective wholesale
16 market platform is supported by adoption of independent and regional grid operation
17 pursuant to Commission policies. In addition, like the Midwest ISO and PJM utilities,
18 the SPP members are subject to independent authority over planning for required
19 transmission facilities and have limited control over timing or location of future projects.

20 Moreover, the group of Proxy TOs is also consistent with the elimination of
21 seams and the push toward a “virtual single market”, as well as the increased

³² Order Conditionally Granting Declaratory Order, Accepting Proposed Formula Rates, Subject to Conditions and Establishing Hearing and Settlement Procedures, Docket No. EL06-109, 118 FERC ¶ 61,087 (2007) (“Duquesne Light Co.”), at P. 73.

1 coordination of system operations among regional utilities, and it recognizes that these
2 firms compete for investment funds from the same pool of potential capital. Considering
3 these common traits, the companies in the group of Proxy TOs provide a sound basis on
4 which to estimate investors required returns and establish the range of reasonableness for
5 the AEP Companies.

6 **Q 33 WOULD IT BE APPROPRIATE TO RELY ON THE DCF RESULTS FOR A**
7 **SINGLE UTILITY OR USE A PROXY GROUP COMPOSED SOLELY OF THE**
8 **SPP TRANSMISSION OWNERS?**

9 A 33 No. Estimating the cost of equity using any method is a stochastic process and the
10 potential for misleading findings increases as the proxy group is narrowed. Apart from
11 being consistent with FERC precedent and guidance, expanding the comparable group to
12 include transmission-owning members of Midwest ISO and PJM is essential to insulate
13 against unpredictable results.

14 Eliminating those SPP transmission owners for which insufficient data is
15 available to apply the Commission's DCF model would result in a group of only five
16 firms. The cost of equity is inherently unobservable and can only be inferred by
17 reference to available capital market data. Any form of analysis that depends on
18 estimates, such as the growth parameter of the DCF model, is subject to measurement
19 error. When the technique is applied using only a limited number of observations (*e.g.*, a
20 proxy group of five companies), there is less confidence that the result (*i.e.*, the cost of
21 equity estimate) is representative. To the extent that the data used to apply the
22 Commission's DCF approach does not capture the expectations that investors have

1 incorporated into current stock prices, the resulting cost of equity estimates will be
2 biased.

3 FERC noted in its July 3, 2003 *Order on Initial Decision* in Docket No. RP00-
4 107-000 that even using a limited group of companies increases the potential for error:

5 Both Staff and Williston agreed that a proxy group of only three
6 companies presented problems because “a single company will have a
7 magnified influence on the group results.” It was with those changing
8 market dynamics in mind that witnesses of both Staff and Williston
9 proposed to expand the group of proxy companies to determine a zone of
10 reasonableness.³³

11 FERC Staff proposed expanding the proxy group to include fifteen firms in *Williston*
12 *Basin*.³⁴ Conceptually, the issue of proxy group size is directly analogous to the use of
13 sampling in statistical analyses. In statistics, a “true” value is often estimated by
14 reference to sample observations, with the analyst having greater confidence in the
15 applicability of the estimated results as the size of the sample increases relative to the
16 population.

17 **Q 34 HOW DID YOU CALCULATE THE DIVIDEND YIELD COMPONENT OF THE**
18 **DCF MODEL FOR THE ELECTRIC UTILITY PROXY GROUP?**

19 A 34 Following Commission policy, average low and high indicated dividend yields were
20 calculated for each electric utility during the six months November 2006 through April
21 2007. These six-month average low and high historical dividend yields were also
22 increased by one-half of the low and high growth rates discussed subsequently to convert
23 them to adjusted dividend yields. The purpose of this adjustment in the Commission’s
24 DCF model is to take into consideration the timing of dividend payments, which are

³³ Williston Basin Interstate Pipeline Co., 104 FERC ¶ 61,036, at 14-15 (Jul. 3, 2003) (“*Williston Basin*”).

1 generally paid quarterly. Multiplying the six-month average dividend yield by a factor of
2 one-plus-one-half the estimated long term growth rate ($1 + 0.5g$) is intended to recognize
3 the impact of quarterly dividend payments in calculating the investor-expected dividend
4 yield.

5 **Q 35 WHAT GROWTH RATES ARE USED IN THE COMMISSION'S ONE-STEP**
6 **DCF METHOD FOR ELECTRIC UTILITIES?**

7 A 35 The one-step DCF method for electric utilities adopted by the Commission employs two
8 growth rates for each firm. The first growth rate is a “sustainable” growth rate calculated
9 by the following formula:

$$g = br + sv$$

11 where: b = expected retention ratio;
12 r = expected earned rate of return;
13 s = percent of common equity expected to be issued
14 annually as new common stock;
15 v = equity accretion ratio.

16 The second growth rate is the consensus 5-year earnings growth forecast published by
17 IBES. These two growth rates are combined with the adjusted dividend yields to develop
18 a cost of equity range for each company.

19 **Q 36 HOW DID YOU CALCULATE THE SUSTAINABLE GROWTH RATE FOR**
20 **THE ELECTRIC UTILITY PROXY GROUP?**

21 A 36 For each electric utility, the expected retention ratio (b) was calculated based on projected
22 dividends and earnings per share from Value Line for 2007, 2008, and their 2010-2012
23 forecast horizon. Likewise, each firm's expected earned rate of return (r) was computed
24 by dividing projected earnings per share by Value Line's corresponding figure for net

³⁴ *Id.* at Appendix B.

1 book value. In *Southern California Edison*, the Commission correctly recognized that if
2 the rate of return, or “r” component of the $br + sv$ growth rate, is based on end-of-year
3 book values, such as those reported by Value Line, it will understate actual returns
4 because of growth in common equity over the year.³⁵ Accordingly, consistent with the
5 Commission’s findings and the theory underlying this approach to estimating investors’
6 growth expectations, an adjustment was incorporated to compute an average rate of
7 return.³⁶ Finally, the percent of common equity expected to be issued annually as new
8 common stock (s) was calculated using projected changes in common shares outstanding
9 over Value Line’s forecast horizon, with the equity accretion ratio (v) being based on
10 each firm’s projected 2010-2012 market-to-book ratio. The resulting sustainable growth
11 rate for each electric utility is shown in column (c) of Exhibit AEP-402.

12 **Q 37 WHAT ARE INVESTMENT ANALYSTS' PROJECTED GROWTH RATES FOR**
13 **THE COMPANIES IN THE ELECTRIC UTILITY PROXY GROUP?**

14 A 37 The 5-year earnings growth forecasts published by IBES for each electric utility in the
15 proxy group are shown in column (d) of Exhibit AEP-402.

16 **Q 38 WHAT WERE THE RESULTS OF APPLYING THE COMMISSION’S ONE-**
17 **STEP DCF APPROACH TO THE PROXY GROUP OF ELECTRIC UTILITIES?**

18 A 38 As shown on Exhibit AEP-402, application of the Commission’s DCF model to the
19 electric utility proxy group resulted in current cost of equity estimates ranging from 6.8
20 percent to 17.5 percent.

³⁵ *Southern California Edison* at 18 and fn. 38.

³⁶ Use of an average return in developing the sustainable growth rate is well supported. See, e.g., Morin, Roger A., “Regulatory Finance: Utilities’ Cost of Capital,” Public Utilities Reports, Inc. (1994), which discusses the need to adjust Value Line’s end-of-year data, consistent with the Commission’s findings in *Southern California Edison*.

1 **Q 39 HAS THE COMMISSION RECOGNIZED THAT IT MAY BE APPROPRIATE**
2 **TO ELIMINATE COST OF EQUITY ESTIMATES THAT FAIL TO MEET**
3 **THRESHOLD TESTS OF ECONOMIC LOGIC?**

4 A 39 Yes. In *Southern California Edison* the Commission noted that adjustments to the zone
5 of reasonableness are justified where applications of its preferred DCF approach produce
6 illogical results:

7 An adjustment to this data is appropriate in the case of PG&E's low-end
8 return of 8.42 percent, which is comparable to the average Moody's "A"
9 grade public utility bond yield of 8.06 percent, for October 1999. Because
10 investors cannot be expected to purchase stock if debt, which has less risk
11 than stock, yields essentially the same return, this low-end return cannot
12 be considered reliable in this case.³⁷

13 More recently, in its October 2006 decision in *Kern River Gas Transmission Company*,
14 the Commission noted that:

15 [T]he 7.31 and 7.32 percent costs of equity for El Paso and Williams
16 found by the ALJ are only 110 and 122 basis points above that average
17 yield for public utility debt.³⁸

18 The Commission upheld the opinion of Staff and the Administrative Law Judge that cost
19 of equity estimates for these two proxy group companies “were too low to be credible.”³⁹

20 Consistent with Commission policy, the DCF range for the proxy group of
21 electric utilities must be adjusted to eliminate cost of equity estimates that fail
22 fundamental tests of economic logic. It is a basic economic principle that investors can
23 be induced to hold more risky assets only if they expect to earn a return to compensate
24 them for their risk bearing. As a result, the rate of return that investors require from a

³⁷ *Southern California Edison* at 22.

³⁸ *Kern River Gas Transmission Company*, Opinion No. 486, 117 FERC ¶ 61,077 (2006) at P. 140 & fn. 227.

³⁹ *Id.*

1 utility's common stock, the most junior and riskiest of its securities, must be considerably
2 higher than the yield offered by senior, long-term debt.

3 The average bond rating associated with the firms in the proxy group is triple-B,
4 with Moody's monthly yields on triple-B bonds averaging approximately 6.1 percent
5 over the six-month period ending April 2007.⁴⁰ In the present instance, low-end cost of
6 equity estimates for two of the proxy group firms exceeded this threshold by 100 basis
7 points or less.⁴¹ In light of the risk-return tradeoff principle, it is inconceivable that
8 investors are not requiring a substantially higher rate of return for holding common stock,
9 which is the riskiest of a utility's securities. As a result, these values provide little
10 guidance as to the returns investors require from the common stock of an electric utility.
11 Similarly, the Staff witness in Docket No. ER06-787-002 concluded that "a reasonable
12 objective standard" would be to exclude low-end DCF estimates that are "less than 100
13 basis points above the recent six-month average yield to maturity on Moody's "Baa"
14 rated Public Utility bond index."⁴²

15 **Q 40 DO YOU BELIEVE THAT THE CURRENT YIELD TO MATURITY FOR**
16 **OUTSTANDING BOND ISSUES SPECIFIC TO EACH UTILITY SHOULD**
17 **SERVE AS THE BASIS FOR APPLYING THIS TEST OF REASONABLENESS?**

18 A 40 No. As in *Southern California Edison* and *Kern River Gas Transmission*, the
19 Commission has not customarily referenced company-specific debt issues but instead
20 employs an average yield on long-term utility bonds of corresponding risk – and for good

⁴⁰ Based on data from Moody's *Credit Perspectives* (Jan. 8, Mar. 19, & May 7, 2007).

⁴¹ As highlighted on Exhibit AEP-402, low-end estimates for Ameren and NiSource, Inc. were 6.8 percent.

⁴² *Prepared Answering Testimony of Commission Staff Witness Edward Alvarez III*, Docket No. ER06-787-002, Exhibit S-11 (January 19, 2007) at 15.

1 reason. As explained earlier, because common equity is a perpetual asset investors are
2 concerned with expectations for the firm's long-term risks and prospects. This does not
3 mean that every investor will buy and hold a particular common stock forever. Rather, it
4 recognizes that even an investor with a relatively short holding period will consider the
5 long-term because of its influence on the price that he or she ultimately receives from the
6 stock when it is sold. In order to mirror this long-term horizon in evaluating the
7 reasonableness of DCF cost of equity estimates, the appropriate comparison is with long-
8 term debt instruments.

9 Meanwhile, the yield for the embedded debt issues of a specific utility will
10 typically reflect a ladder of shorter-term maturities, which does not match the long-term
11 horizon relevant to an evaluation of common equity returns. In addition to different
12 terms to maturity, using yields on company-specific bonds as a benchmark is fraught with
13 other problems. The yield to maturity on any particular bond is influenced by specific
14 attributes of the securities, such as coupon rate, call provisions or convertibility, and size
15 of the issue. Indeed, the Financial Analysis Branch of the Commission previously noted
16 some of these problems in a 1992 study:

17 Determining the bond cost has proven more difficult, however. Ideally, all
18 utilities would have a bond: with identical terms and conditions; maturing
19 in 30 years ... and bear a coupon similar to the market rate, thus
20 accurately reflecting the debt cost of the company. For most companies
21 bonds with identical terms were not available.⁴³

22 Because of these attributes, the yields for company-specific debt issues do not provide a
23 reliable basis on which to evaluate the results of the Commission's DCF model. These

⁴³ Financial Analysis Branch, *Risk Premium Study* (Aug. 4, 1992) at 3.

1 measurement problems are avoided by using average yields for risk-comparable long-
2 term utility bonds, such as the Moody's triple-B rate averages.

3 **Q 41 WHAT OTHER OBJECTIVE EVIDENCE DEMONSTRATES THAT COST OF**
4 **EQUITY ESTIMATES OF 6.8 PERCENT ARE NOT LOGICAL?**

5 A 41 Expectations for a continued upward trend in long-term capital costs further supports a
6 finding that these estimates are illogical and should be disregarded. Widely referenced
7 projections, which the Commission relies on in applying its DCF model for gas
8 transmission companies, continue to anticipate that long-term interest rates will increase.
9 Specifically, the most recent forecast of GlobalInsight calls for double-A public utility
10 bond yields to average 6.24 percent in 2008,⁴⁴ while the EIA anticipates that double-A
11 public utility bond yields will average 6.85 percent in 2008.⁴⁵ As shown below in Table
12 1, with the average yield spread between double-A and triple-B utility bonds over the six
13 months ended April 2007 being 41 basis points, these forecasts imply an average triple-B
14 bond yield of 6.96 percent for 2008, or 7.42 percent over the 5-year period 2008-2012:

⁴⁴ GlobalInsight, "The U.S. Economy: The 30-Year Focus" (First-Quarter 2007) at Table 34.

⁴⁵ Energy Information Administration, "Annual Energy Outlook 2007" (Feb. 2007) at Table 19.

1
2

TABLE 1
IMPLIED BBB BOND YIELD

<u>Line No.</u>		<u>2008</u>	<u>2008-12</u>
1	Projected AA Utility Yield		
2	GlobalInsight (a)	6.24%	6.71%
3	EIA (b)	6.85%	7.30%
4	Average	6.55%	7.01%
5	BBB – AA Yield Spread (c)	0.41%	0.41%
6	Implied BBB Utility Yield	6.96%	7.42%

- (a) GlobalInsight, “The U.S. Economy: The 30-Year Focus” (First-Quarter 2007) at Table 34.
- (b) Energy Information Administration, “Annual Energy Outlook 2007,” (Feb. 2007) at Table 19.
- (c) Based on monthly average bond yields for the six months Nov. 2006 – Apr. 2007 reported in Moody’s *Credit Perspectives*.

3 Given that low-end cost of equity estimates of 6.8 percent are below investors’
4 expectations for comparable utility bond yields, these cannot be considered credible
5 estimates of investors’ required return on common stocks.

6 **Q 42 IS THERE ANY BASIS TO EXCLUDE COST OF EQUITY ESTIMATES AT THE**
7 **HIGH END OF THE RANGE OF REASONABLENESS FOR THE PROXY**
8 **GROUP?**

9 A 42 Yes. In a November 2004 Order in New England RTO, the Commission determined that
10 a cost of equity estimate at the high end of the range of reasonableness might also be
11 excluded if it is determined to be an extreme outlier.⁴⁶ Meanwhile, the upper end of the
12 cost of equity range produced by the DCF analysis presented in Exhibit No. AEP-402
13 was based on a cost of equity estimate of 17.5 percent for Exelon Corporation, with the

⁴⁶ Order Accepting Partial Settlement, Subject to Conditions; Accepting in Part, Compliance Filings; and Granting in Part, and Denying, in Part, Requests for Rehearing, 109 FERC ¶ 61,147 (2004) (“November NE-RTO Order”) at P. 205.

1 underlying growth rate being equity to 14.5 percent. Accordingly, this high-end cost of
2 equity estimate is properly excluded under the rationale adopted by the Commission in its
3 *November NE-RTO Order*.

4 **Q 43 WHAT ROE IS IMPLIED BY YOUR DCF RESULTS?**

5 A 43 As shown on Exhibit No. AEP-402, eliminating these illogical low- and high-end values
6 resulted in an adjusted range of reasonableness for the proxy group of electric utilities
7 ranging from 7.4 percent to 15.4 percent, with a midpoint of 11.4 percent.

8 **Q 44 WHAT DO EXPECTED TRENDS IN INTEREST RATES IMPLY WITH**
9 **RESPECT TO INVESTORS' REQUIRED RATE OF RETURN FOR THE FIRMS**
10 **IN THE PROXY GROUP?**

11 A 44 Considering the ongoing consensus that long-term interest rates will continue to increase
12 in the coming years, current bond yields are likely to understate capital market
13 requirements at the time the outcome of this proceeding becomes effective and beyond.
14 Recognizing that investors' return requirements can and do change substantially, the
15 Commission has routinely adjusted DCF cost of equity estimates to reflect changes in
16 capital market conditions, typically by reference to yield differentials for 10-year
17 Treasury notes.⁴⁷

18 Under established policy, the DCF cost of equity is increased or decreased by the
19 full amount of any change in the benchmark government bond yield, so long as the
20 resulting equity return remains within the zone of reasonableness. Table 2 below
21 compares the published projections of GlobalInsight, and EIA with the average yield on
22 10-year Treasury notes for the six months November 2006 through April 2007:

1
2

TABLE 2
CHANGE IN 10-YEAR TREASURY YIELD

Line No.	10-Year Treasury Yields	2008	2008-12
1	<u>Projected</u>		
2	GlobalInsight (a)	5.09%	5.30%
3	EIA (b)	<u>5.23%</u>	<u>5.47%</u>
5	Average	5.16%	5.39%
6	<u>Actual</u>		
7	Nov. 2006 – Apr. 2007 (c)	<u>4.65%</u>	<u>4.65%</u>
8	Change in Treasury Yield	0.51%	0.74%

- (a) GlobalInsight, “The U.S. Economy: The 30-Year Focus” (First-Quarter 2007) at Table 34.
 (b) Energy Information Administration, “Annual Energy Outlook 2007,” (Feb. 2007) at Table 19.
 (c) <http://www.federalreserve.gov/releases/h15/data.htm>.

3 As shown above, these widely referenced projections imply an increase in 10-year
 4 Treasury yields of 51 basis points for 2008, or 74 basis points over the 2008-2012 time
 5 period. Accordingly, employing an approach analogous to that adopted by the
 6 Commission in past proceedings suggests an adjustment to account for expected changes
 7 in capital market conditions on the order of at least 50 basis points.

C. ROE Benchmarks

8 **Q 45 WHAT OTHER ANALYSES DID YOU CONDUCT TO ESTIMATE THE COST**
 9 **OF EQUITY?**

10 A 45 I also evaluated the cost of equity for the AEP Companies against ROE benchmarks
 11 developed using the CAPM and comparable earnings methods. While *Order Nos. 679*
 12 and *679-A* did not establish a requirement to implement alternatives to FERC’s DCF
 13 approach, the Commission stated its willingness to consider other methods on a case-by-

⁴⁷ See, e.g., *System Energy Resources, Inc.*, Opinion No. 446, 92 FERC ¶61,119 (2000) and

1 case basis. As noted previously, the Commission has also recognized that it may be
2 appropriate to consider the results of alternative methods. Moreover, in contrast to
3 applications of the CAPM using historical, realized rates of return, which have been
4 largely rejected by the Commission in the past, my CAPM analysis specifically
5 incorporated forward-looking expectations that are consistent with the assumptions of
6 this approach.

7 **Q 46 WHAT OTHER EVIDENCE SUPPORTS YOUR REFERENCE TO**
8 **ALTERNATIVE ROE BENCHMARKS?**

9 A 46 Because the cost of equity is unobservable, no single method should be viewed in
10 isolation. While the DCF model has been routinely relied on in regulatory proceedings as
11 one guide to investors' required return, it is a blunt tool that should never be used
12 exclusively. Regulators have customarily considered the results of alternative approaches
13 in determining allowed returns.⁴⁸ It is widely recognized that no single method can be
14 regarded as a panacea; all approaches having their own advantages and shortcomings.
15 For example, a publication of the Society of Utility and Financial Analysts (formerly the
16 National Society of Rate of Return Analysts), concluded that:

17 Each model requires the exercise of judgment as to the reasonableness of
18 the underlying assumptions of the methodology and on the reasonableness
19 of the proxies used to validate the theory. Each model has its own way of
20 examining investor behavior, its own premises, and its own set of
21 simplifications of reality. Each method proceeds from different
22 fundamental premises, most of which cannot be validated empirically.

Appalachian Power Company, Opinion No. 423, 83 FERC ¶ 61,335 (1998).

⁴⁸ For example, a NARUC survey reported that 26 regulatory jurisdictions ascribe to no specific method for setting allowed ROEs, with the results of all approaches being considered. "Utility Regulatory Policy in the U.S. and Canada, 1995-1996," National Association of Regulatory Utility Commissioners (December 1996).

1 Investors clearly do not subscribe to any singular method, nor does the
2 stock price reflect the application of any one single method by investors.⁴⁹

3 Moreover, evidence suggests that reliance on the DCF model as a tool for
4 estimating investors' required rate of return has declined outside the regulatory sphere,
5 with the CAPM being "the dominant model for estimating the cost of equity."⁵⁰
6 *Regulatory Finance: Utilities Cost of Capital* noted the inherent difficulties of the DCF
7 approach:

8 [C]autious and judgment are required in interpreting the results of DCF
9 models because of (1) the questionable applicability of the DCF model to
10 utility stocks in certain market environments, (2) the effect of declining
11 earnings and dividends on financial inputs to the DCF model and biases
12 caused by the effect of changes in risk and growth, and (3) the conceptual
13 and practical difficulties associated with the growth component of the
14 DCF model.⁵¹

15 The publication concluded, "If the cost of equity estimation process is limited to one
16 methodology, such as DCF, it may severely bias the results."⁵²

17 **Q 47 PLEASE DESCRIBE THE CAPM.**

18 A 47 The CAPM is a theory of market equilibrium that measures risk using the beta
19 coefficient. Under the CAPM, investors are assumed to be fully diversified, so the
20 relevant risk of an individual asset (e.g., common stock) is its volatility relative to the
21 market as a whole. Beta reflects the tendency of a stock's price to follow changes in the
22 market. A stock that tends to respond relatively less to market movements has a beta less

⁴⁹ Parcell, David C., "The Cost of Capital – A Practitioner's Guide," *Society of Utility and Regulatory Financial Analysts* (1997) at Part 2, p. 4.

⁵⁰ See, e.g., Bruner, R.F., Eades, K.M., Harris, R.S., and Higgins, R.C., "Best Practices in Estimating Cost of Capital: Survey and Synthesis," *Financial Practice and Education* (1998).

⁵¹ Morin, Roger A., "Regulatory Finance: Utilities' Cost of Capital," *Public Utilities Reports, Inc.* (1994) at 238.

⁵² *Id.*

1 than 1.00, while stocks that tend to move more than the market have betas greater than
2 1.00. The CAPM is mathematically expressed as:

$$3 \quad R_j = R_f + \beta_j(R_m - R_f)$$

4 where: R_j = required rate of return for stock j;
5 R_f = risk-free rate;
6 R_m = expected return on the market portfolio; and,
7 β_j = beta, or systematic risk, for stock j.

8 Like the DCF model, the CAPM is an *ex-ante*, or forward-looking model based on
9 expectations of the future. As a result, in order to produce a meaningful estimate of
10 investors' required rate of return, the CAPM must be applied using data that reflects the
11 expectations of actual investors in the market.

12 **Q 48 HOW DID YOU APPLY THE CAPM TO ESTIMATE THE COST OF EQUITY**
13 **FOR THE PROXY TOS PROXY GROUP?**

14 A 48 Application of the CAPM to the utilities in the proxy group based on a forward-looking
15 estimate for investors' required rate of return from common stocks is presented on Exhibit
16 AEP-403. In order to capture the expectations of today's investors in current capital
17 markets, the expected market rate of return was estimated by conducting a DCF analysis
18 on the dividend paying firms in the S&P 500.

19 The dividend yield for each firm was obtained from Value Line, with the growth
20 rate being equal to the average of the earnings growth projections for each firm published
21 by IBES and Value Line, with each firm's dividend yield and growth rate being weighted
22 by its proportionate share of total market value. Based on the weighted average of the
23 projections for the 361 individual firms, current estimates imply an average growth rate
24 over the next five years of 11.2 percent. Combining this average growth rate with a
25 dividend yield of 2.1 percent results in a current cost of equity estimate for the market as

1 a whole of approximately 13.3 percent. Subtracting a 4.9 percent risk-free rate based on
2 the average yield on 20-year Treasury bonds for the six months ended April 2007
3 produced a market equity risk premium of 8.4 percent. Multiplying this risk premium by
4 the respective Value Line betas for the utilities in the group of Proxy TOs, and then
5 adding the resulting risk premiums to the average long-term Treasury bond yield,
6 indicated a base ROE in the range of 10.3 to 16.3 percent, with a midpoint of 13.3
7 percent.

8 **Q 49 WHAT OTHER BENCHMARKS DID YOU DEVELOP TO EVALUATE THE**
9 **ROE FOR THE AEP COMPANIES?**

10 A 49 As I noted earlier, I also evaluated the ROE using the comparable earnings method.
11 Reference to rates of return available from alternative investments of comparable risk can
12 provide an important benchmark in assessing the return necessary to assure confidence in
13 the financial integrity of a firm and its ability to attract capital. This comparable earnings
14 approach is consistent with the economic underpinnings for a fair rate of return
15 established by the Supreme Court in *Hope* and *Bluefield*. Moreover, it avoids the
16 complexities and limitations of capital market methods and instead focuses on the returns
17 earned on book equity, which are readily available to investors.

18 **Q 50 WHAT RATES OF RETURN ARE INDICATED FOR UTILITIES BASED ON**
19 **THIS APPROACH?**

20 A 50 With respect to expectations for electric utilities generally, the March 30, 2007 edition of
21 Value Line reports that its analysts anticipate an average rate of return on common equity
22 for the electric utility industry of 11.0 percent in 2007, 2008, and over its three-to-five

1 year forecast horizon.⁵³ Meanwhile, Value Line expects that natural gas distribution
2 utilities will earn an average rate of return on common equity of 11.5 percent in 2007,
3 and 12.0 percent over the years 2010 through 2012.⁵⁴ Considering the Commission's
4 policy goal of promoting increased infrastructure investment, these expected earned
5 returns for electric and gas utilities provide a meaningful benchmark in establishing an
6 ROE for jurisdictional transmission operations that is sufficient to successfully compete
7 for necessary capital investment.

8 For the firms in the utility proxy group specifically, the returns on common equity
9 projected by Value Line over its three-to-five year forecast horizon are shown on Exhibit
10 AEP-404. Consistent with the rationale underlying the development of the br + sv growth
11 rates, these year-end values were converted to average returns using the same adjustment
12 factor discussed earlier. As shown on Exhibit AEP-404, after eliminating potential high-
13 end outliers, Value Line's projections suggested an ROE in the range of 8.1 percent to
14 16.9 percent, with the midpoint being 12.5 percent.

15 **Q 51 CAN THE COMPARABLE EARNINGS METHOD BE APPLIED TO OTHER**
16 **FIRMS OF SIMILAR RISK?**

17 A 51 Yes. Under the regulatory standards established by *Hope* and *Bluefield*, the salient
18 criteria in establishing a meaningful benchmark to evaluate a fair rate of return is relative
19 risk, not the particular business activity or degree of regulation. Utilities must compete
20 for capital, not just against firms in their own industry, but with other investment
21 opportunities of comparable risk. Consistent with this accepted regulatory standard, I

⁵³ The Value Line Investment Survey (Mar. 30, 2007) at 695.

⁵⁴ The Value Line Investment Survey (Mar. 16, 2007) at 460.

1 also applied the comparable earnings approach based on a reference group of companies
2 in the unregulated sector of the economy.

3 My assessment of comparable risk relied on two objective benchmarks for the
4 risks associated with common stocks – Value Line’s Safety Rank and beta. The Safety
5 Rank, which ranges from “1” (Safest) to “5” (Riskiest), is intended to capture the total
6 risk of a stock, while Value Line’s beta values provide a measure of stock price
7 variability as compared with the firms in the New York Stock Exchange Composite
8 Index. The Value Line Safety Rankings for the firms in the proxy group range from “1”
9 to “3”, with beta values for the group of Proxy TOs averaging 0.90. Accordingly, my
10 reference group was composed of those U.S. companies followed by Value Line that: (1)
11 pay common dividends, (2) have a Safety Rank of “3” or above, and (3) have beta values
12 between 0.85 and 0.95. Value Line’s projections indicate that its analysts expect that
13 rates of return on shareholders equity for the resulting group of 170 firms will average
14 15.5 percent, with the median being 13.0 percent.⁵⁵

15 **Q 52 WHAT RETURN ON EQUITY IS INDICATED BY THE RESULTS OF THE**
16 **COMPARABLE EARNINGS APPROACH?**

17 A 52 Based on the results discussed above, I concluded that the comparable earnings approach
18 implies a fair rate of return on equity of 12.5 percent.

D. Flotation Costs

19 **Q 53 WHAT OTHER CONSIDERATIONS ARE RELEVANT IN SETTING THE ROE**
20 **FOR A UTILITY?**

⁵⁵ www.valueline.com (Retrieved May 17, 2007).

1 A 53 The common equity used to finance the investment in utility assets is provided from
2 either the sale of stock in the capital markets or from retained earnings not paid out as
3 dividends. When equity is raised through the sale of common stock, there are costs
4 associated with "floating" the new equity securities. These flotation costs include
5 services such as legal, accounting, and printing, as well as the fees and discounts paid to
6 compensate brokers for selling the stock to the public. Also, some argue that the "market
7 pressure" from the additional supply of common stock and other market factors may
8 further reduce the amount of funds a utility nets when it issues common equity.

9 **Q 54 IS THERE AN ESTABLISHED MECHANISM FOR A UTILITY TO**
10 **RECOGNIZE EQUITY ISSUANCE COSTS?**

11 A 54 No. While debt flotation costs are recorded on the books of the utility, amortized over
12 the life of the issue, and thus increase the effective cost of debt capital, there is no similar
13 accounting treatment to ensure that equity flotation costs are recorded and ultimately
14 recognized. Alternatively, no rate of return is authorized on flotation costs necessarily
15 incurred to obtain a portion of the equity capital used to finance plant. In other words,
16 equity flotation costs are not included in a utility's rate base because neither that portion of
17 the gross proceeds from the sale of common stock used to pay flotation costs is available to
18 invest in plant and equipment, nor are flotation costs capitalized as an intangible asset.
19 Unless some provision is made to recognize these issuance costs, a utility's revenue
20 requirements will not fully reflect all of the costs incurred for the use of investors' funds.
21 Because there is no accounting convention to accumulate the flotation costs associated with
22 equity issues, they must be accounted for indirectly, with an upward adjustment to the
23 cost of equity being the most logical mechanism.

1 **Q 55 IS THE NEED FOR A FLOTATION COST ADJUSTMENT TO COMPENSATE**
2 **FOR PAST EQUITY ISSUES RECOGNIZED IN THE FINANCIAL**
3 **LITERATURE?**

4 A 55 Yes. In a *Public Utilities Fortnightly* article, Brigham, Aberwald, and Gapenski
5 demonstrated that even if no further stock issues are contemplated, a flotation cost
6 adjustment in all future years is required to keep shareholders whole, and that the
7 flotation cost adjustment must consider total equity, including retained earnings.⁵⁶
8 Similarly, *Regulatory Finance: Utilities' Cost of Capital* contains the following
9 discussion:

10 Another controversy is whether the underpricing allowance should still be
11 applied when the utility is not contemplating an imminent common stock
12 issue. Some argue that flotation costs are real and should be recognized in
13 calculating the fair rate of return on equity, but only at the time when the
14 expenses are incurred. In other words, the flotation cost allowance should
15 not continue indefinitely, but should be made in the year in which the sale
16 of securities occurs, with no need for continuing compensation in future
17 years. This argument implies that the company has already been
18 compensated for these costs and/or the initial contributed capital was
19 obtained freely, devoid of any flotation costs, which is an unlikely
20 assumption, and certainly not applicable to most utilities. ... The flotation
21 cost adjustment cannot be strictly forward-looking unless all past flotation
22 costs associated with past issues have been recovered.⁵⁷

23 **Q 56 WHAT IS THE MAGNITUDE OF THE ADJUSTMENT TO THE “BARE**
24 **BONES” COST OF EQUITY TO ACCOUNT FOR ISSUANCE COSTS?**

25 A 56 One of the most common methods used to account for flotation costs in regulatory
26 proceedings is to apply an average flotation-cost percentage to a utility's dividend yield.

⁵⁶ Brigham, E.F., Aberwald, D.A., and Gapenski, L.C., “Common Equity Flotation Costs and Rate Making,” *Public Utilities Fortnightly* (May, 2, 1985).

⁵⁷ Morin, Roger A., “Regulatory Finance: Utilities' Cost of Capital,” *Public Utilities Reports* (1994) at 175.

1 Based on a review of the finance literature, *Regulatory Finance: Utilities' Cost of Capital*
2 concluded:

3 The flotation cost allowance requires an estimated adjustment to the return
4 on equity of approximately 5% to 10%, depending on the size and risk of
5 the issue.⁵⁸

6 Alternatively, a study of data from Morgan Stanley regarding issuance costs associated
7 with utility common stock issuances suggests an average flotation cost percentage of 3.6
8 percent.⁵⁹

9 Applying these expense percentages to a representative dividend yield for a utility
10 of 3.6 percent implies a flotation cost adjustment on the order of 13 to 36 basis points.
11 While my recommendation does not include a specific adjustment for flotation costs, this
12 is a legitimate consideration that supports the reasonableness of the ROE requested by the
13 AEP Companies in this case.

14 **IV. RETURN ON EQUITY FOR THE AEP COMPANIES**

15 **Q 57 WHAT IS THE PURPOSE OF THIS SECTION?**

16 A 57 This section addresses the economic requirements for the ROE applicable to the
17 jurisdictional utility operations of the AEP Companies and presents my conclusions
18 regarding a reasonable incentive-based ROE range of reasonableness. It examines other
19 factors properly considered in determining a fair rate of return, including the relationship
20 between ROE and preservation of a utility's financial integrity and the ability to attract
21 capital.

⁵⁸ Id. at 166.

⁵⁹ *Application of Yankee Gas Services Company for a Rate Increase*, DPUC Docket No. 04-06-01, Direct Testimony of George J. Eckenroth (Jul. 2, 2004) at Exhibit GJE-11.1. Updating the results presented by Mr. Eckenroth through April 2005 also resulted in an average flotation cost percentage of 3.6%.

A. Implications for Financial Integrity

1 **Q 58 WHY IS IT IMPORTANT TO ALLOW THE AEP COMPANIES AN ADEQUATE**
2 **ROE?**

3 A 58 Given the social and economic importance of the utility industry, it is essential to
4 maintain reliable and economical service to all consumers. While the AEP Companies
5 remain committed to deliver reliable service, a utility's ability to fulfill its mandate can
6 be compromised if it lacks the necessary financial wherewithal or is unable to earn a
7 return sufficient to attract capital. Coupled with the ongoing potential for energy market
8 volatility, the AEP Companies' plans for significant infrastructure investment and
9 ongoing exposure to regulatory uncertainty pose a number of potential challenges that
10 might require the relatively swift commitment of significant capital resources in order to
11 maintain the high level of service that customers deserve.

12 The major rating agencies have noted the financial pressures associated with
13 AEP's ambitious program of capital additions, including its initiative to invest
14 substantially in transmission infrastructure. Investors understand just how swiftly
15 unforeseen circumstances can lead to deterioration in a utility's financial condition, and
16 stakeholders have discovered first hand how difficult and complex it can be to remedy the
17 situation after the fact. For a utility with an obligation to provide reliable service,
18 investors' increased reticence to supply additional capital during times of crisis highlights
19 the necessity of preserving the flexibility necessary to overcome periods of adverse
20 capital market conditions.

21 **Q 59 WHAT ROLE DOES REGULATION PLAY IN ENSURING ACCESS TO**
22 **CAPITAL FOR THE AEP COMPANIES?**

1 A 59 Considering investors' heightened awareness of the risks associated with the utility
2 industry and the damage that results when a utility's financial flexibility is compromised,
3 supportive regulation remains crucial to the AEP Companies' access to capital. Investors
4 recognize that constructive regulation is a key ingredient in supporting utility credit
5 ratings and financial integrity, particularly during times of adverse conditions. S&P
6 noted that:

7 Regulatory rulings have returned to center stage as a dominant factor in
8 assessing companies' credit quality. These decisions will be critical for an
9 industry that in many jurisdictions is nearing the end of extended
10 transition periods and will be making significant capital investment in
11 infrastructure during the next several years.⁶⁰

12 Moody's recently echoed these sentiments, noting that "regulatory relationships are
13 becoming more important" in an era of rising costs and uncertainties.⁶¹ Investors
14 recognize that regulation has its own risks, with Moody's specifically noting the need for
15 ongoing support from regulators as the AEP Companies initiate "an intense investment
16 period" in utility infrastructure to meet customers' needs and ensure reliability.⁶²

17 **Q 60 WHAT DANGER DOES AN INADEQUATE RATE OF RETURN POSE TO THE**
18 **AEP COMPANIES?**

19 A 60 Considering the magnitude of the events that have transpired since the third quarter of
20 2000, investors' sensitivity to market and regulatory uncertainties has increased
21 dramatically. At the same time, the AEP Companies' plans include significant plant

⁶⁰ Standard & Poor's Corporation, "Industry Report Card: U.S. Electric/Gas/Water," *RatingsDirect* (May 3, 2005) at 1.

⁶¹ Moody's Investors Service, "Regulatory Pressures Increase for U.S. Electric Utilities," *Special Comment* (March 2007).

⁶² Moody's Investors Service, "Credit Opinion: Public Service Company of Oklahoma," *Global Credit Research* (Dec. 11, 2006); "Credit Opinion: Southwestern Electric Power Company," *Global Credit Research* (Dec. 11, 2006).

1 investment to ensure that the energy needs of their service territories are met in a reliable
2 and cost-effective manner. While providing the infrastructure necessary to further the
3 goals of enhancing the bulk power transmission system and meeting the energy needs of
4 customers is certainly desirable, it imposes additional financial responsibilities on the
5 AEP Companies. Given the magnitude of the capital expenditure program contemplated
6 by AEP and its operating utilities, the perception of a lack of regulatory support at the
7 Commission would undermine the AEP Companies' credit standing. S&P warned
8 investors that "harmful regulatory decisions" that compromise the ability of the AEP
9 Companies to recover rate base investments and other costs "could lead to a negative
10 stance or lower ratings."⁶³ To continue to meet potential challenges successfully and
11 economically, it is crucial that the AEP Companies receive adequate support to maintain
12 their credit standing.

13 **Q 61 DO CUSTOMERS ALSO BENEFIT BY ENHANCING THE UTILITY'S**
14 **FINANCIAL FLEXIBILITY?**

15 A 61 Yes. While providing an ROE that is sufficient to maintain the AEP Companies' ability
16 to attract capital, even under duress, is consistent with the economic requirements
17 embodied in the Supreme Court's *Hope* and *Bluefield* decisions, it is also in the best
18 interests of the AEP Companies' customers. Ultimately, it is customers and the service
19 area economy that enjoy the benefits that come from ensuring that the utility has the
20 financial wherewithal to take whatever actions are required to ensure a reliable energy
21 supply. By the same token, customers also bear a significant burden when the ability of
22 the utility to attract capital is impaired and service quality is compromised.

⁶³ Standard & Poor's Corporation, "Summary: Public Service Co. of Oklahoma," *RatingsDirect*

1 **Q 62 WHAT ELSE SHOULD BE CONSIDERED IN EVALUATING A REASONABLE**
2 **ROE FOR THE AEP COMPANIES?**

3 A 62 The AEP Companies and other participating transmission owners face risks simply by
4 transferring functional control of their transmission assets to SPP, which participates in
5 an industry that is in the process of restructuring and where business practices and
6 regulatory policy continue to experience significant flux. By participating in an RTO, the
7 AEP Companies have given up significant control over decisions about whether to invest
8 in new transmission and how their transmission assets will be operated. At a financial
9 conference hosted by the Fitch IBCA, Duff & Phelps rating agency, one speaker
10 summarized the uncertain environment faced by RTO participants:

11 [Y]ou can put on all the new technology you like, spend all your money,
12 and the rate you will get in return is unclear and someone else is going to
13 manage it for you.⁶⁴

14 **Q 63 DO FORMULA RATES ELIMINATE RISK FROM AN INVESTOR'S**
15 **PERSPECTIVE?**

16 A 63 No. Formula rates are a two-edged sword. Formula rates might modify risk at the
17 wholesale level to the extent that they eliminate the need for utilities to file rate cases
18 when costs are increasing, but they also put utilities at risk for retroactive downward rate
19 adjustments under Section 206 of the Federal Power Act – a risk that does not exist under
20 fixed rates. In addition, under formula rates that are tied to cost, there is no opportunity
21 to earn in excess of the allowed rate of return in between rate cases, as may be the case
22 with stated rates. Investors therefore see very limited strategic opportunity to earn higher

(Jan. 29, 2007).

⁶⁴ Fitch IBCA, Duff & Phelps, “Electric Markets: The Past Year and the Next 10”, *Special Report* at 8 (Dec. 12, 2001).

1 returns to balance the risks associated with potential disallowances by regulators. Also,
2 most of the money for transmission must still be recovered from consumers at the retail
3 level, which typically (and in the case of the AEP Companies) has a greater impact on
4 financial performance.

B. RTO Participation Adder

5 **Q 64 HAS THE COMMISSION RECOGNIZED THAT AN ROE ADDER FOR RTO**
6 **PARTICIPATION IS APPROPRIATE?**

7 A 64 Yes. The decision to provide this incentive is well supported, both from policy and
8 capital attraction reasons, and the Commission has consistently affirmed its support for
9 an ROE incentive for RTO participation. For example, in the Commission's policy
10 statement on RTO formation incentives, FERC stated that "any entity that transfers
11 operational control of transmission facilities to a Commission-approved RTO would
12 qualify for an incentive adder of 50 basis points on its ROE for all such facilities
13 transferred."⁶⁵ The Commission has determined that the public interest is better served if
14 functional control of the grid is performed by an independent RTO and if new
15 transmission investment is undertaken with the wider focus and enhanced stakeholder
16 participation provided through an RTO-driven process, rather than under isolated, utility-
17 by-utility planning. As the Commission noted more recently:

18 A regional planning process is very important to meeting regional
19 transmission needs, and, we believe it will produce benefits for
20 customers.⁶⁶

⁶⁵ Proposed Pricing Policy for Efficient Operation and Expansion of Transmission Grid, 102 FERC ¶ 61,032 (2003) (Pricing Policy Statement).

⁶⁶ *Order No. 679* at P. 332.

1 Such comprehensive operations, planning and decision making under an RTO framework
2 should be encouraged, fostered, and rewarded in order to achieve the public policy goals
3 mandated by Congress. Moreover, given past precedent authorizing incentive returns for
4 RTO participants,⁶⁷ investors have come to expect such added returns when they fund
5 projects for which the utility is no longer the sole operational or planning entity.

6 The Commission affirmed its policy of providing ROE-based incentives for
7 public utilities that join, or continue membership in, an RTO in *Order Nos. 679* and *679-*

8 A. While FERC elected to consider the incentive request on a case-by-case basis, rather
9 than creating a generic adder, the Commission concluded that:

10 [E]ntities that have already joined, and that remain members of, an RTO,
11 ISO, or other Commission-approved Transmission Organization, are
12 eligible to receive this incentive. The basis for the incentive is a
13 recognition of the benefits that flow from membership in such an
14 organization and the fact that continuing membership is generally
15 voluntary.⁶⁸

16 Thus, incentive rate treatment to recognize the AEP Companies' ongoing participation in
17 an RTO is consistent with past precedent, the Commission's guidelines, and investors'
18 expectations and should be approved.

C. ROE Recommendation

19 **Q 65 WHAT IS YOUR CONCLUSION REGARDING A FAIR ROE FOR THE AEP**
20 **COMPANIES?**

⁶⁷ See, e.g., New England RTO [CITE]; PJM Interconnection, L.L.C., 106 FERC ¶ 61,280 at P. 246; PJM Interconnection, L.L.C., 104 FERC ¶ 61,124 at P 74 (2003); Allegheny Power System Operating Companies, et al., 106 FERC ¶ 61,003 (2004).

⁶⁸ *Order No. 679* at P. 331. Similarly, the Commission concluded in *Order No. 679-A*, "We affirm the finding in the Final Rule that the incentive applies to all utilities joining transmission organizations, irrespective of the date they join, based on a reading of section 219 in its entirety." [P. 86]

1 A 65 Because the transmission facilities of the AEP Companies are operated within the scope
2 of SPP, investors' required rate of return on equity was estimated by reference to a group
3 of electric utilities comprised of TOs participating in SPP and the broader RTO markets
4 with which SPP interacts. Based on the adjusted range of reasonableness produced by
5 applying the Commission's DCF approach to the group of Proxy TOs, I recommend an
6 ROE range of reasonableness of 7.4 percent to 15.4 percent, with the midpoint of this
7 range being 11.4 percent. In light of the fact that the AEP Companies have relinquished
8 functional control of their transmission operations to SPP, an incentive adder of 50 basis
9 points for RTO participation should be added to this base.

10 In evaluating a reasonable ROE for the AEP Companies, it is important to
11 consider investors' continued focus on the unsettled conditions in restructured power
12 markets, as well as other development in the electric utility industry, such as heightened
13 exposure to regulatory risks. Moreover, an ROE of 11.9 percent falls well within the
14 zone of reasonableness and is warranted at this critical juncture, given the importance of
15 supporting the financial capability of the AEP Companies as they seek to maintain their
16 credit standing while undertaking the capital investment necessary to develop and
17 enhance utility infrastructure. The cost of providing the AEP Companies an adequate
18 return is small relative to the potential benefits that a strong utility can have in providing
19 reliable service. Considering investors' heightened awareness of the risks associated with
20 the utility industry and the damage that results when a utility's financial flexibility is
21 compromised, supportive regulation is crucial.

22 **Q 66 DOES THIS CONCLUDE YOUR DIRECT TESTIMONY IN THIS CASE?**

23 A 66 Yes, it does.

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

American Electric Power Service Corporation on
behalf of:

Public Service Company of Oklahoma

Southwestern Electric Power Company

Docket No. ER07-___-000

AFFIDAVIT OF WITNESS

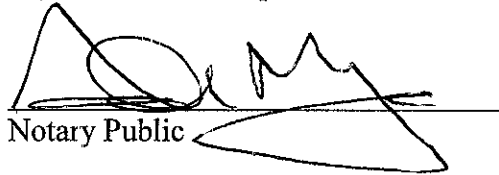
I, the undersigned, being duly sworn, depose and say, under penalty of perjury, that the Prepared Direct Testimony of William E. Avera is the testimony of the undersigned, and that the exhibits sponsored by me to the best of my knowledge, information and belief, are true, correct, accurate and complete, and I hereby adopt said testimony as if given by me in formal hearing, under oath.



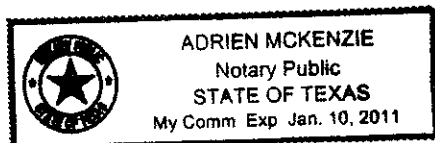
William E. Avera

Subscribed and sworn to before me this
13th day of June, 2007.

My Commission expires: 1/10/2011



Notary Public



WILLIAM E. AVERA

FINCAP, INC.
Financial Concepts and Applications
Economic and Financial Counsel

3907 Red River
Austin, Texas 78751
(512) 458-4644
FAX (512) 458-4768
fincap@texas.net

Summary of Qualifications

Ph.D. in economics and finance; Chartered Financial Analyst (CFA[®]) designation; extensive expert witness testimony before courts, alternative dispute resolution panels, regulatory agencies and legislative committees; lectured in executive education programs around the world on ethics, investment analysis, and regulation; undergraduate and graduate teaching in business and economics; appointed to leadership positions in government, industry, academia, and the military.

Employment

Principal,
FINCAP, Inc.
(Sep. 1979 to present)

Financial, economic and policy consulting to business and government. Perform business and public policy research, cost/benefit analyses and financial modeling, valuation of businesses (over 150 entities valued), estimation of damages, statistical and industry studies. Provide strategy advice and educational services in public and private sectors, and serve as expert witness before regulatory agencies, legislative committees, arbitration panels, and courts.

*Director, Economic Research
Division,*
Public Utility Commission of Texas
(Dec. 1977 to Aug. 1979)

Responsible for research and testimony preparation on rate of return, rate structure, and econometric analysis dealing with energy, telecommunications, water and sewer utilities. Testified in major rate cases and appeared before legislative committees and served as Chief Economist for agency. Administered state and federal grant funds. Communicated frequently with political leaders and representatives from consumer groups, media, and investment community.

Manager, Financial Education,
International Paper Company
New York City
(Feb. 1977 to Nov. 1977)

Directed corporate education programs in accounting, finance, and economics. Developed course materials, recruited and trained instructors, liaison within the company and with academic institutions. Prepared operating budget and designed financial controls for corporate professional development program.

Lecturer in Finance,
The University of Texas at Austin
(Sep. 1979 to May 1981)
Assistant Professor of Finance,
(Sep. 1975 to May 1977)

Taught graduate and undergraduate courses in financial management and investment theory. Conducted research in business and public policy. Named Outstanding Graduate Business Professor and received various administrative appointments.

Assistant Professor of Business,
University of North Carolina at
Chapel Hill
(Sep. 1972 to Jul. 1975)

Taught in BBA, MBA, and Ph.D. programs. Created project course in finance, Financial Management for Women, and participated in developing Small Business Management sequence. Organized the North Carolina Institute for Investment Research, a group of financial institutions that supported academic research. Faculty advisor to the Media Board, which funds student publications and broadcast stations.

Education

Ph.D., Economics and Finance,
University of North Carolina at
Chapel Hill
(Jan. 1969 to Aug. 1972)

Elective courses included financial management, public finance, monetary theory, and econometrics. Awarded the Stonier Fellowship by the American Bankers' Association and University Teaching Fellowship. Taught statistics, macroeconomics, and microeconomics.

Dissertation: *The Geometric Mean Strategy as a Theory of Multiperiod Portfolio Choice*

B.A., Economics,
Emory University, Atlanta, Georgia
(Sep. 1961 to Jun. 1965)

Active in extracurricular activities, president of the Barkley Forum (debate team), Emory Religious Association, and Delta Tau Delta chapter. Individual awards and team championships at national collegiate debate tournaments.

Professional Associations

Received Chartered Financial Analyst (CFA) designation in 1977; Vice President for Membership, Financial Management Association; President, Austin Chapter of Planning Executives Institute; Board of Directors, North Carolina Society of Financial Analysts; Candidate Curriculum Committee, Association for Investment Management and Research; Executive Committee of Southern Finance Association; Vice Chair, Staff Subcommittee on Economics and National Association of Regulatory Utility Commissioners (NARUC); Appointed to NARUC Technical Subcommittee on the National Energy Act.

Teaching in Executive Education Programs

University-Sponsored Programs: Central Michigan University, Duke University, Louisiana State University, National Defense University, National University of Singapore, Texas A&M University, University of Kansas, University of North Carolina, University of Texas.

Business and Government-Sponsored Programs: Advanced Seminar on Earnings Regulation, American Public Welfare Association, Association for Investment Management and Research, Congressional Fellows Program, Cost of Capital Workshop, Electricity Consumers Resource Council, Financial Analysts Association of Indonesia, Financial Analysts Review, Financial Analysts Seminar at Northwestern University, Governor's Executive Development Program of Texas, Louisiana Association of Business and Industry, National Association of Purchasing Management, National Association of Tire Dealers, Planning Executives Institute, School of Banking of the South, State of Wisconsin Investment Board, Stock Exchange of Thailand, Texas Association of State Sponsored Computer Centers, Texas Bankers' Association, Texas Bar Association, Texas Savings and Loan League, Texas Society of CPAs, Tokyo Association of Foreign Banks, Union Bank of Switzerland, U.S. Department of State, U.S. Navy, U.S. Veterans Administration, in addition to Texas state agencies and major corporations.

Presented papers for Mills B. Lane Lecture Series at the University of Georgia and Heubner Lectures at the University of Pennsylvania. Taught graduate courses in finance and economics in evening program at St. Edward's University in Austin from January 1979 through 1998.

Expert Witness Testimony

Testified in 240 cases before regulatory agencies addressing cost of capital, regulatory policy, rate design, and other economic and financial issues.

Federal Agencies: Federal Communications Commission, Federal Energy Regulatory Commission, Surface Transportation Board, Interstate Commerce Commission, and the Canadian Radio-Television and Telecommunications Commission.

State Regulatory Agencies: Alaska, Arizona, Arkansas, California, Colorado, Connecticut, Delaware, Florida, Hawaii, Idaho, Illinois, Indiana, Kansas, Maryland, Michigan, Missouri, Nevada, New Mexico, North Carolina, Ohio, Oklahoma, Oregon, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Virginia, Washington, West Virginia, Wisconsin, and Wyoming.

Testified in 40 cases before federal and state courts, arbitration panels, and alternative dispute tribunals (80 depositions given) regarding damages, valuation, antitrust liability, fiduciary duties, and other economic and financial issues.

Board Positions and Other Professional Activities

Audit Committee and Outside Director, Georgia System Operations Corporation (electric system operator for member-owned electric cooperatives in Georgia); Chairman, Board of Print Depot, Inc. and FINCAP, Inc.; Co-chair, Synchronous Interconnection Committee, appointed by Public Utility Commission of Texas and approved by governor; Operator of AAA Ranch, a certified organic producer of agricultural products; Appointed to Organic Livestock Advisory Committee by Texas Agricultural Commissioner Susan Combs; Appointed by Texas Railroad Commissioners to study group for *The UP/SP Merger: An Assessment of the Impacts on the State of Texas*; Appointed by Hawaii Public Utilities Commission to team reviewing affiliate relationships of Hawaiian Electric Industries; Chairman, Energy Task Force, Greater Austin-San Antonio Corridor Council; Consultant to Public Utility Commission of Texas on cogeneration policy and other matters; Consultant to Public Service Commission of New Mexico on cogeneration policy; Evaluator of Energy Research Grant Proposals for Texas Higher Education Coordinating Board.

Community Activities

Board Member, Sustainable Food Center; Chair, Board of Deacons, Finance Committee, and Elder, Central Presbyterian Church of Austin; Founding Member, Orange-Chatham County (N.C.) Legal Aid Screening Committee.

Military

Captain, U.S. Naval Reserve (retired after 28 years service); Commanding Officer, Naval Special Warfare Engineering Support Unit; Officer-in-charge of SWIFT patrol boat in Vietnam; Enlisted service as weather analyst (advanced to second class petty officer).

Bibliography

Monographs

Ethics and the Investment Professional (video, workbook, and instructor's guide) and *Ethics Challenge Today* (video), Association for Investment Management and Research (1995)

"Definition of Industry Ethics and Development of a Code" and "Applying Ethics in the Real World," in *Good Ethics: The Essential Element of a Firm's Success*, Association for Investment Management and Research (1994)

"On the Use of Security Analysts' Growth Projections in the DCF Model," with Bruce H. Fairchild in *Earnings Regulation Under Inflation*, J. R. Foster and S. R. Holmberg, eds. Institute for Study of Regulation (1982)

An Examination of the Concept of Using Relative Customer Class Risk to Set Target Rates of Return in Electric Cost-of-Service Studies, with Bruce H. Fairchild, Electricity Consumers Resource Council (ELCON) (1981); portions reprinted in *Public Utilities Fortnightly* (Nov. 11, 1982)

"Usefulness of Current Values to Investors and Creditors," *Research Study on Current-Value Accounting Measurements and Utility*, George M. Scott, ed., Touche Ross Foundation (1978)

"The Geometric Mean Strategy and Common Stock Investment Management," with Henry A. Latané in *Life Insurance Investment Policies*, David Cummins, ed. (1977)

Investment Companies: Analysis of Current Operations and Future Prospects, with J. Finley Lee and Glenn L. Wood, American College of Life Underwriters (1975)

Articles

"Should Analysts Own the Stocks they Cover?" *The Financial Journalist*, (March 2002)

"Liquidity, Exchange Listing, and Common Stock Performance," with John C. Groth and Kerry Cooper, *Journal of Economics and Business* (Spring 1985); reprinted by National Association of Security Dealers

"The Energy Crisis and the Homeowner: The Grief Process," *Texas Business Review* (Jan.–Feb. 1980); reprinted in *The Energy Picture: Problems and Prospects*, J. E. Pluta, ed., Bureau of Business Research (1980)

"Use of IFPS at the Public Utility Commission of Texas," *Proceedings of the IFPS Users Group Annual Meeting* (1979)

"Production Capacity Allocation: Conversion, CWIP, and One-Armed Economics," *Proceedings of the NARUC Biennial Regulatory Information Conference* (1978)

"Some Thoughts on the Rate of Return to Public Utility Companies," with Bruce H. Fairchild in *Proceedings of the NARUC Biennial Regulatory Information Conference* (1978)

"A New Capital Budgeting Measure: The Integration of Time, Liquidity, and Uncertainty," with David Cordell in *Proceedings of the Southwestern Finance Association* (1977)

"Usefulness of Current Values to Investors and Creditors," in *Inflation Accounting/Indexing and Stock Behavior* (1977)

"Consumer Expectations and the Economy," *Texas Business Review* (Nov. 1976)

"Portfolio Performance Evaluation and Long-run Capital Growth," with Henry A. Latané in *Proceedings of the Eastern Finance Association* (1973)

Book reviews in *Journal of Finance* and *Financial Review*. Abstracts for *CFA Digest*. Articles in *Carolina Financial Times*.

Selected Papers and Presentations

"The Who, What, When, How, and Why of Ethics", San Antonio Financial Analysts Society (Jan. 16, 2002). Similar presentation given to the Austin Society of Financial Analysts (Jan. 17, 2002)

"Ethics for Financial Analysts," Sponsored by Canadian Council of Financial Analysts: delivered in Calgary, Edmonton, Regina, and Winnipeg, June 1997. Similar presentations given to Austin Society of Financial Analysts (Mar. 1994), San Antonio Society of Financial Analysts (Nov. 1985), and St. Louis Society of Financial Analysts (Feb. 1986)

"Cost of Capital for Multi-Divisional Corporations," Financial Management Association, New Orleans, Louisiana (Oct. 1996)

"Ethics and the Treasury Function," Government Treasurers Organization of Texas, Corpus Christi, Texas (Jun. 1996)

"A Cooperative Future," Iowa Association of Electric Cooperatives, Des Moines (December 1995). Similar presentations given to National G & T Conference, Irving, Texas (June 1995), Kentucky Association of Electric Cooperatives Annual Meeting, Louisville (Nov. 1994), Virginia, Maryland, and Delaware Association of Electric Cooperatives Annual Meeting, Richmond (July 1994), and Carolina Electric Cooperatives Annual Meeting, Raleigh (Mar. 1994)

"Information Superhighway Warnings: Speed Bumps on Wall Street and Detours from the Economy," Texas Society of Certified Public Accountants Natural Gas, Telecommunications and Electric Industries Conference, Austin (Apr. 1995)

"Economic/Wall Street Outlook," Carolinas Council of the Institute of Management Accountants, Myrtle Beach, South Carolina (May 1994). Similar presentation given to Bell Operating Company Accounting Witness Conference, Santa Fe, New Mexico (Apr. 1993)

"Regulatory Developments in Telecommunications," Regional Holding Company Financial and Accounting Conference, San Antonio (Sep. 1993)

"Estimating the Cost of Capital During the 1990s: Issues and Directions," The National Society of Rate of Return Analysts, Washington, D.C. (May 1992)

"Making Utility Regulation Work at the Public Utility Commission of Texas," Center for Legal and Regulatory Studies, University of Texas, Austin (June 1991)

"Can Regulation Compete for the Hearts and Minds of Industrial Customers," Emerging Issues of Competition in the Electric Utility Industry Conference, Austin (May 1988)

- "The Role of Utilities in Fostering New Energy Technologies," Emerging Energy Technologies in Texas Conference, Austin (Mar. 1988)
- "The Regulators' Perspective," Bellcore Economic Analysis Conference, San Antonio (Nov. 1987)
- "Public Utility Commissions and the Nuclear Plant Contractor," Construction Litigation Superconference, Laguna Beach, California (Dec. 1986)
- "Development of Cogeneration Policies in Texas," University of Georgia Fifth Annual Public Utilities Conference, Atlanta (Sep. 1985)
- "Wheeling for Power Sales," Energy Bureau Cogeneration Conference, Houston (Nov. 1985).
- "Asymmetric Discounting of Information and Relative Liquidity: Some Empirical Evidence for Common Stocks" (with John Groth and Kerry Cooper), Southern Finance Association, New Orleans (Nov. 1982)
- "Used and Useful Planning Models," Planning Executive Institute, 27th Corporate Planning Conference, Los Angeles (Nov. 1979)
- "Staff Input to Commission Rate of Return Decisions," The National Society of Rate of Return Analysts, New York (Oct. 1979)
- "Electric Rate Design in Texas," Southwestern Economics Association, Fort Worth (Mar. 1979)
- "Discounted Cash Life: A New Measure of the Time Dimension in Capital Budgeting," with David Cordell, Southern Finance Association, New Orleans (Nov. 1978)
- "The Relative Value of Statistics of Ex Post Common Stock Distributions to Explain Variance," with Charles G. Martin, Southern Finance Association, Atlanta (Nov. 1977)
- "An ANOVA Representation of Common Stock Returns as a Framework for the Allocation of Portfolio Management Effort," with Charles G. Martin, Financial Management Association, Montreal (Oct. 1976)
- "A Growth-Optimal Portfolio Selection Model with Finite Horizon," with Henry A. Latané, American Finance Association, San Francisco (Dec. 1974)
- "An Optimal Approach to the Finance Decision," with Henry A. Latané, Southern Finance Association, Atlanta (Nov. 1974)
- "A Pragmatic Approach to the Capital Structure Decision Based on Long-Run Growth," with Henry A. Latané, Financial Management Association, San Diego (Oct. 1974)
- "Multi-period Wealth Distributions and Portfolio Theory," Southern Finance Association, Houston (Nov. 1973)
- "Growth Rates, Expected Returns, and Variance in Portfolio Selection and Performance Evaluation," with Henry A. Latané, Econometric Society, Oslo, Norway (Aug. 1973)

FERC DCF MODEL

Company	(a) <u>6 Mo.Div. Yield</u>		(b) <u>Adjusted Div. Yield</u>		(c) <u>Growth Rates</u>		(d)	(e) <u>Implied Cost of Equity</u>		(f)
	Low	High	Low	High	br + sv	I/B/E/S	Low	High		
1 ALIETE, Inc.	3.2%	3.4%	3.3%	3.5%	8.0%	5.0%	8.3%	--	11.6%	
2 Alliant Energy	2.9%	3.2%	3.0%	3.3%	4.8%	6.0%	7.8%	--	9.3%	
3 Ameren	4.7%	4.9%	4.7%	5.1%	2.0%	6.0%	6.8%	--	11.1%	
4 American Electric Pwr.	3.4%	3.6%	3.5%	3.7%	5.8%	4.0%	7.5%	--	9.6%	
5 Consolidated Edison	4.6%	4.8%	4.7%	4.9%	3.1%	3.0%	7.7%	--	8.0%	
6 Constellation Energy	2.0%	2.2%	2.1%	2.3%	12.0%	13.0%	14.2%	--	15.3%	
7 Dominion Resources	3.2%	3.4%	3.3%	3.5%	8.7%	7.0%	10.3%	--	12.3%	
8 DPL, Inc.	3.4%	3.6%	3.5%	3.8%	10.7%	9.0%	12.5%	--	14.5%	
9 Empire District Elec	5.1%	5.4%	5.1%	5.5%	2.6%	3.0%	7.8%	--	8.5%	
10 Exelon Corp.	2.5%	2.7%	2.6%	2.9%	14.5%	9.0%	11.6%	--	17.5%	
11 FirstEnergy Corp.	2.9%	3.2%	3.0%	3.3%	6.9%	8.0%	9.9%	--	11.3%	
12 Great Plains Energy	5.1%	5.3%	5.2%	5.5%	3.5%	5.0%	8.7%	--	10.5%	
13 Integrys Energy Group	4.2%	4.5%	4.3%	4.6%	5.4%	5.0%	9.3%	--	10.0%	
14 MDU Resources Group	1.9%	2.1%	2.0%	2.2%	9.2%	7.0%	9.0%	--	11.4%	
15 NiSource, Inc.	3.7%	3.9%	3.8%	4.0%	3.4%	3.0%	6.8%	--	7.4%	
16 OGE Energy Corp.	3.4%	3.6%	3.4%	3.7%	5.4%	4.0%	7.4%	--	9.1%	
17 Otter Tail Power	3.5%	3.7%	3.5%	3.8%	3.9%	5.0%	7.4%	--	8.8%	
18 Pepco Holdings	3.7%	4.0%	3.8%	4.1%	4.3%	7.0%	8.1%	--	11.1%	
19 PPI	2.9%	3.2%	3.0%	3.4%	7.4%	12.0%	10.4%	--	15.4%	
20 PS Enterprise Group	3.1%	3.4%	3.2%	3.5%	9.0%	9.0%	12.2%	--	12.6%	
21 Vectren Corp.	4.3%	4.5%	4.4%	4.7%	4.0%	5.0%	8.4%	--	9.7%	
22 Westar Energy	3.7%	4.0%	3.8%	4.1%	3.9%	4.0%	7.7%	--	8.1%	
23 Wisconsin Energy	2.0%	2.1%	2.0%	2.1%	6.5%	8.0%	8.6%	--	10.1%	
24 Xcel Energy, Inc.	3.7%	3.9%	3.8%	4.0%	3.9%	6.0%	7.7%	--	10.0%	
Range of Reasonableness							6.8%	--	17.5%	
Midpoint									12.1%	
Adjusted Range of Reasonableness							7.4%		15.4%	
Midpoint									11.4%	

(a) Six-month average dividend yield for November 2006 - April 2007.

(b) Six-month dividend yield adjusted for one-half years' growth.

(c) Average of projections based on data from The Value Line Investment Survey (Mar. 2, Mar. 30, & May 11, 2007).

(d) S&P's Earnings Guide (April 2007).

(e) Sum of low growth rate and corresponding adjusted dividend yield.

(f) Sum of high growth rate and corresponding adjusted dividend yield.

CAPM MODEL

Company	(a)	(b)	(c)	(d)	(e)	(f)	(g)	
	Div Yield	Proj. Growth	Cost of Equity	Risk-Free Rate	Risk Premium	Beta	Implied Cost of Equity	
1 ALLEIE, Inc.	2.1%	11.2%	13.3%	4.9%	8.4%	0.90	12.5%	
2 Alliant Energy	2.1%	11.2%	13.3%	4.9%	8.4%	0.95	12.9%	
3 Ameren	2.1%	11.2%	13.3%	4.9%	8.4%	0.75	11.2%	
4 American Electric Pwr.	2.1%	11.2%	13.3%	4.9%	8.4%	1.35	16.2%	
5 Consolidated Edison	2.1%	11.2%	13.3%	4.9%	8.4%	0.75	11.2%	
6 Constellation Energy	2.1%	11.2%	13.3%	4.9%	8.4%	0.95	12.9%	
7 Dominion Resources	2.1%	11.2%	13.3%	4.9%	8.4%	1.05	13.7%	
8 DPL, Inc.	2.1%	11.2%	13.3%	4.9%	8.4%	0.95	12.9%	
9 Empire District Elec.	2.1%	11.2%	13.3%	4.9%	8.4%	0.80	11.6%	
10 Exelon Corp.	2.1%	11.2%	13.3%	4.9%	8.4%	0.90	12.5%	
11 FirstEnergy Corp.	2.1%	11.2%	13.3%	4.9%	8.4%	0.85	12.0%	
12 Great Plains Energy	2.1%	11.2%	13.3%	4.9%	8.4%	0.95	12.9%	
13 Integrys Energy Group	2.1%	11.2%	13.3%	4.9%	8.4%	0.85	12.0%	
14 MDU Resources Group	2.1%	11.2%	13.3%	4.9%	8.4%	1.00	13.3%	
15 NiSource, Inc.	2.1%	11.2%	13.3%	4.9%	8.4%	0.95	12.9%	
16 OGE Energy Corp.	2.1%	11.2%	13.3%	4.9%	8.4%	0.75	11.2%	
17 Otter Tail Power	2.1%	11.2%	13.3%	4.9%	8.4%	0.65	10.3%	
18 Pepco Holdings	2.1%	11.2%	13.3%	4.9%	8.4%	0.90	12.5%	
19 PPL	2.1%	11.2%	13.3%	4.9%	8.4%	0.95	12.9%	
20 PS Enterprise Group	2.1%	11.2%	13.3%	4.9%	8.4%	1.00	13.3%	
21 Vectren Corp.	2.1%	11.2%	13.3%	4.9%	8.4%	0.90	12.5%	
22 Westar Energy	2.1%	11.2%	13.3%	4.9%	8.4%	0.90	12.5%	
23 Wisconsin Energy	2.1%	11.2%	13.3%	4.9%	8.4%	0.80	11.6%	
24 Xcel Energy, Inc.	2.1%	11.2%	13.3%	4.9%	8.4%	0.90	12.5%	
Range of Reasonableness							10.3%	16.2%
Midpoint								13.3%

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retrieved Feb. 9, 2007).

(b) Weighted average of IBES and Value Line growth rates for the dividend paying firms in the S&P 500 based on data from Standard & Poor's Earnings Guide (Jan. 2007) and www.valueline.com (Retrieved Feb. 9, 2007).

(c) (a) + (b).

(d) Average yield on 20-year Treasury bonds for Nov. 2006 - Apr. 2007 from the Federal Reserve Board at <http://www.federalreserve.gov/releases/h15/data.htm>.

(e) (c) - (d).

(f) The Value Line Investment Survey (Mar. 2, Mar. 30, & May 11, 2007).

(g) (d) + (e) x (f).

UTILITY PROXY GROUP

<u>Company</u>	(a) <u>Expected Return on Common Equity</u>	(b) <u>Adjustment Factor</u>	(c) <u>Adjusted Return on Common Equity</u>
ALLETE, Inc.	12.0%	1.0289	12.3%
Alliant Energy	9.5%	1.0211	9.7%
Ameren	9.0%	1.0137	9.1%
American Electric Pwr.	12.5%	1.0291	12.9%
Consolidated Edison	9.0%	1.0170	9.2%
Constellation Energy	16.5%	1.0574	17.4%
Dominion Resources	16.0%	1.0540	16.9%
DPL, Inc.	18.5%	1.0534	19.5%
Empire District Elec.	11.0%	1.0163	11.2%
Exelon Corp.	19.0%	1.0594	20.1%
FirstEnergy Corp.	13.5%	1.0321	13.9%
Great Plains Energy	11.0%	1.0217	11.2%
Integrus Energy Group	10.0%	1.0195	10.2%
MDU Resources Group	11.0%	1.0443	11.5%
NiSource, Inc.	8.0%	1.0183	8.1%
OGE Energy Corp.	11.5%	1.0279	11.8%
Otter Tail Power	9.5%	1.0231	9.7%
Pepco Holdings	11.0%	1.0139	11.2%
PPL	21.5%	1.0303	22.2%
PS Enterprise Group	13.5%	1.0404	14.0%
Vectren Corp.	11.0%	1.0168	11.2%
Westar Energy	9.5%	1.0161	9.7%
Wisconsin Energy	11.0%	1.0282	11.3%
Xcel Energy, Inc.	10.5%	1.0174	10.7%
Range of Reasonableness			8.1% 22.2%
Midpoint			15.1%
Adjusted Range of Reasonableness			8.1% 16.9%
Midpoint			12.5%

(a) 3-5 year projections from The Value Line Investment Survey (Mar. 2, Mar. 30, & May 11, 2007).

(b) See Exhibit AEP-400 at 31-32.

(c) (a) x (b)