BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-01______

DIRECT TESTIMONY OF WILLIAM E. AVERA

REPRESENTING THE AVISTA CORPORATION

Exhibit No. T-__ (WEA-T)

DIRECT TESTIMONY OF WILLIAM E. AVERA

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I. INTRODUCTION

Q. Please state your name and business address.

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

Q. By whom are you employed and in what capacity?

A. I am a principal in Financial Concepts and Applications, Inc. (FINCAP), a firm engaged in financial, economic, and policy consulting to business and government.

A. Qualifications

Q. Describe your educational background, professional qualifications, and prior experience.

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

In 1977 I joined the staff of the Public Utility Commission of Texas (PUCT) as Director of the Economic Research Division. During my tenure at the PUC, I managed a division responsible for financial analysis, cost allocation and rate design, economic and financial research, and data processing systems, and I testified in a number of cases on a variety of financial and economic issues. Since leaving the PUCT in 1979, I have been engaged as a consultant. I have participated in a wide range of analytical assignments involving utility-related matters on behalf of utilities, industrial customers, municipalities, and regulatory commissions. I have previously testified before the Federal Energy Regulatory Commission (FERC), as well as the Federal Communications Commission (FCC), the Surface Transportation Board (and its predecessor, the Interstate Commerce Commission), the Canadian Radio-Television and Telecommunications Commission, and regulatory agencies, courts, and legislative committees in 28 states, including the Washington Utilities and Transportation Commission (WUTC).

With the approval of then–Governor George W. Bush, I was appointed by the PUCT to the Synchronous Interconnection Committee to advise the Texas legislature on the costs and benefits of connecting Texas to the national electric transmission grid. Currently, I am serving as an outside director of Georgia System Operations Corporation, the system operations arm of the nation's largest member-owned supplier of electricity.

I have served as Lecturer in the Finance Department at the University of Texas at Austin and taught in the evening graduate program at St. Edward's University for twenty years. In addition, I have lectured on economic and regulatory topics in programs sponsored by universities and industry groups. For the last 20 years I have taught in hundreds of educational programs for financial analysts in programs sponsored by the Association for Investment Management and Research, the Financial Analysts Review, and local financial analysts societies. These programs have been presented in Asia, Europe, and North America, including the Financial Analysts Seminar at Northwestern University. I hold the Chartered Financial Analyst (CFA) designation and have served as Vice President for Membership of the Financial Management Association. I have also served on the Board of Directors of the North Carolina Society of Financial Analysts. I was elected Vice Chairman of the National Association of Regulatory Commissioners (NARUC) Subcommittee on Economics and appointed to NARUC's Technical Subcommittee on the National Energy Act. I have also served as an officer of various other professional organizations and societies. A resume containing the details of my experience and qualifications is attached as Appendix A.

B. Overview

Q. What is the purpose of your testimony?

A. My purpose here is to present to the WUTC my independent assessment of the overall fair rate of return for Avista Corp.'s (Avista) jurisdictional electric utility operations.

Q. Are you sponsoring any exhibits to be introduced in this proceeding?

A. Yes, I am. My exhibit consists of 7 schedules and 1 appendix. It has been marked for identification as Exhibit No. __ (WEA-T).

Q. Please summarize the basis of your knowledge and conclusions concerning the issues to which you are testifying in this hearing.

A. I utilized a variety of sources of information in preparing my analyses and testimony in this case that a person in my capacity would normally rely upon. I am familiar with the organization, finances, and operations of Avista from my participation in Avista's last recent rate proceedings before the WUTC and the Idaho Public Utilities Commission (IPUC). In addition, I also submitted testimony on behalf of Avista in UE-010395 regarding the recovery of power costs through the deferral mechanism. In connection with the present filing, I had discussions with corporate management and reviewed numerous documents relating to Avista, including bond rating agency reports and financial filings. I also reviewed information relating to capital markets generally and investor perceptions, requirements, and expectations for utilities specifically. These sources, coupled with my experience in the fields of finance and utility regulation, enabled me to acquire a working knowledge of Avista and are the basis for my conclusions.

Q What is the role of the rate of return in setting a utility's rates?

A. The rate of return compensates investors for the use of their capital to finance the plant and equipment necessary to provide utility service. Investors commit capital only if they expect to earn a return on their investment commensurate with returns available from alternative investments with comparable risks. To be consistent with sound regulatory economics and the standards set forth by the Supreme Court in the *Bluefield*[1] and *Hope*[2] cases, a utility's allowed should be sufficient to (1) fairly compensate capital invested in the utility, (2) enable the utility to offer a return adequate to attract new capital on reasonable terms, and (3) maintain the utility's financial integrity.

Q. How did you go about developing a fair rate of return for Avista?

A. I first reviewed the operations and finances of Avista and the general conditions in the utility industry and the economy. With this as a background, I evaluated the reasonableness of the capital structure authorized for Avista by the WUTC in Docket No. UE-991606 and calculated average costs of debt and preferred. I developed the principles underlying the cost of equity concept and then conducted various quantitative analyses to estimate the cost of equity for two groups of reference utilities. These included discounted cash flow (DCF) analyses and risk premium methods encompassing alternative approaches and studies. From the cost of equity range indicated by my analyses, a fair rate of return on equity was selected taking into account the economic requirements and specific risks for Avista, as well as other factors (*e.g.*, flotation costs) that are properly considered in setting a fair rate of return on equity. Finally, the findings of these analyses were combined to

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[1] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.W. 679 (1923).
[2] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

calculate an overall rate of return applicable to Avista's jurisdictional electric utility operations.

C. Summary of Conclusions

Q. What are your conclusions regarding the capital structure used by Avista to calculate an overall rate of return?

A. The capital structure I recommend for Avista is identical to that approved by the WUTC in its Final Order in Docket No. UE-991606 little more than a year ago. This capitalization is composed of 45 percent long-term debt, 4 percent short-term debt, 7.5 percent trust preferred securities, 1.5 percent preferred stock, and 42 percent common equity. This capital structure:

- *Should help to limit controversy and allow parties to avoid an otherwise contentious issue;*
- *Remains reasonable when evaluated relative to the two reference groups of electric utilities used to estimate the cost of equity;*
- *Contains less common equity than the average capitalization authorized for electric utilities over the last five years; and,*
- *Falls within agency guidelines for the lowest investment grade bond rating.*

Q. How were the costs assigned to the debt and preferred components of the capital structure determined?

A. The costs associated with debt capital reflect embedded interest rates, adjusted for amortization of capitalized issuance costs over the average term of the respective issues, and incorporate proforma adjustments to reflect the refinancing of debt maturities and the impact of lower credit ratings on short-term sources. Similarly, the cost of the preferred components of the capital structure were based on the dividend yield for each of Avista's preferred series, including amortization of related issuance expense and an anticipated offering of trust preferred securities.

Q. What are your findings regarding the cost of equity?

A. My analyses of the cost of equity focused on two proxy groups of electric utilities and indicated that:

- *The current cost of equity for a single-A rated electric utility is in the 12.25 to 13.25 percent after incorporating an allowance for equity flotation costs;*
- *Because of differences in investment risk, the results of these various quantitative analyses for the proxy groups are not directly applicable to Avista's jurisdictional electric utility operations;*
- *While the average bond ratings for the firms in the electric utility industry groups is single-A, Avista's senior debt is rated low triple-B and its unsecured debt is rated double-B, which falls below investment grade. Avista's weak financial measures and lower credit standing imply significantly greater investment risk and a corresponding increase in investors' required rate of return;*
- *The reference groups used to estimate the cost of equity do not face the same exposure to power costs that confronts Avista;*
- *Adjustment mechanisms that allow pass-through of fuel and purchased power costs are widely prevalent in other jurisdictions, especially those that have not undergone restructuring; and,*
- *In contrast to Avista's electric utility operations, which are exposed to the added risks imposed by fluctuations in streamflows, the proxy groups referenced in estimating the cost of equity do not rely on hydroelectric generation to any significant extent.*

Q. What is your recommended fair rate of return on equity for Avista's jurisdictional electric operations?

A. Based on the results of my analyses, and considering Avista's relative investment risks, I concluded that:

- *To compensate for the additional risks associated with Avista's lower bond ratings and weakened financial position, investors would require a rate of return at least at the very top of the range indicated for the reference groups of electric utilities, or 13.25 percent;*
- *Because the reference groups used to estimate the cost of equity do not face the uncertainties associated with Avista's exposure to volatility in power supply costs, my recommendation already considers the reduction in risk attributable to Avista's requested PCA;*

- *Nevertheless, incorporating a maximum downward adjustment of 50 basis points to reflect Avista's requested PCA results in a fair rate of return on equity of 12.75 percent;*
- *On the other hand, if a PCA is not approved for Avista, investors would be exposed to the risks of competitive power markets while assuming a continued obligation to provide reliable service at regulated prices; and,*
- *To compensate for bearing these asymmetrical risks, investors' required rate of return would likely exceed the 16.9 percent cost of equity indicated for the firms in the S&P 500.*

Q. What overall rate of return do you recommend be applied to Avista's rate base?

A. Combining the capital structure discussed above with the respective costs of each component, including a 12.75 percent cost of equity, resulted in an overall rate of return on Avista's invested capital of 10.39 percent. A return of this magnitude is necessary to:

- *Provide Avista the financial flexibility and access to capital markets that is required to ensure reliable and economic service;*
- *Bolster the confidence of the investment community and resolve overhanging regulatory uncertainties;*
- *Stem any further deterioration in Avista's already weakened credit standing that would compromise its ability to fund construction and ongoing operations; and,*
- *Avoid the daunting complexities and significantly greater costs for all stakeholders that inevitably accompany the collapse of a utility's financial integrity.*

Considering investors' heightened awareness of the risks associated with volatile wholesale power markets and the damage that results when a utility's financial flexibility is compromised, supportive regulation is perhaps more crucial now than at any time in the past. The cost of providing Avista an adequate return is small relative to both the potential benefits that a strong utility can have in providing reliable service and the extreme burden imposed by financial failure.

II. FUNDAMENTAL ANALYSES

Q. What is the purpose of this section?

A. As a predicate to subsequent quantitative analyses, this section briefly reviews Avista's operations and finances. In addition, it examines the risks and prospects for the electric utility industry and conditions in the capital markets and the general economy. An understanding of the fundamental factors driving the risks and prospects of electric utilities is essential in developing an informed opinion of investors' expectations and requirements, that are the bases of a fair rate of return.

A. Avista Corp.

Q. Briefly describe Avista.

A. Formerly The Washington Water Power Company (WWP), Avista is a diversified energy, information, and technology company headquartered in Spokane, Washington. Avista's operations are organized into two lines of business. The Avista Utilities operating division is comprised of state-regulated utility activities, including retail electric and natural gas distribution and transmission services and energy generation. Avista's utility segment provides electric and natural gas utility service within a 26,000 square mile area of eastern Washington and northern Idaho, with gas distribution service also being provided in northeast and southwest Oregon and in the South Lake Tahoe region of California.

Avista Energy, a wholly owned subsidiary, is engaged in electric and natural gas marketing and trading, primarily within the eleven Western states comprising the Western System Coordinating Council. Avista Advantage, for its part, is a leading provider of internet-based specialty billing and information services. Other business entities include Avista Labs, involved in the development of fuel cells. During September 2001, Avista announced its plans to dispose of substantially all of the assets of Avista Communications, a provider of integrated, high-speed telecommunications services to communities in the Northwest. Mr. Gary Ely also describes the activities of Avista's subsidiaries in his testimony. As of September 30, 2001, Avista had total assets of approximately $4.7 billion, with consolidated revenues totaling over $3.6 billion for the most recent fiscal year.

Q. Please describe Avista's electric utility operations.

A. Avista provides retail electric service to approximately 313,000 customers, with principal industries in the area including agriculture, mining, and forestry, as well as health care, electronic and other manufacturing, and tourism. Approximately 40 percent of 2000 retail electric revenues were from residential customers, with 38 percent from commercial and 22 percent from industrial users and street lighting.

With a combined capacity of approximately 1,471 Megawatts (MW), Avista's generating facilities include 8 hydroelectric generating stations (956 MW) located in Idaho, Montana, and Washington. In addition Avista holds a 15 percent interest in the coal-fired Colstrip plant (222 MW) and has two natural gas-fired facilities (244 MW) used primarily to meet peak demand. Avista also owns a wood-fired plant with a generating capacity of approximately 49 MW. Purchased power and exchanges provided approximately 72 percent of Avista's kwh requirements in 2000. The electrical output of Avista's hydroelectric plants, which has a significant effect on total energy costs, is dependent on stream flows. Mr. Kelly Norwood, another company witness, discusses the variability and recent drought conditions associated with Avista's hydroelectric system in more detail.

Avista's retail electric operations are subject to the jurisdiction of the WUTC, the IPUC, and the Montana Public Service Commission, and at the federal level by the Federal Energy Regulatory Commission (FERC). Additionally, all but one of Avista's hydroelectric facilities are subject to licensing under the Federal Power Act, which is administered by FERC. After a prolonged period of planning and consultation with interested parties, Avista received a new operating license covering its two largest hydroelectric facilities (Cabinet Gorge and Noxon Rapids) during 2000. Avista agreed to institute various protection, mitigation, and enhancement measures in order to address environmental concerns while preserving the peak and load following operations of the facilities. The license covering five hydroelectric plants on the Spokane River expires in August 2007, and discussions with stakeholders are already underway. Relicensing is not automatic under federal law, and Avista must demonstrate that it has operated its facilities in the public interest, which includes adequately addressing environmental concerns.

Q. What ratings have been assigned to Avista's long-term debt?

A. The ratings on Avista's senior secured debt were recently downgraded to the lowest triple-B level by the two major bond rating agencies – Moody's Investors Service (*Moody's*) and Standard & Poor's Corporation (*S&P*). This low triple-B rating represents the very bottom rung of the bond rating agencies' ladder of "investment grade" ratings. Meanwhile, concerns over Avista's financial condition and ongoing uncertainties surrounding its ability to recover power costs prompted both *Moody's* and *S&P* to drop the ratings on Avista's senior unsecured debt to double-B. As support for its decision to lower Avista's corporate credit rating to "BB+", *S&P* stated that:

> The downgrade reflect Avista's substantially weakened financial profile, which is not expected to recover to levels commensurate with those of investment-grade companies over the near term, considerable uncertainty surrounding the regulatory environment in Washington despite the recently

> approved 25% rate surcharge, and management's ongoing challenges to ensure adequate liquidity until a final regulatory order is approved.[3]

Moody's noted that these concerns could lead to further reductions in Avista's credit standing going forward:

> The outlook for Avista's ratings is negative, reflecting the still considerable challenges that the company must overcome to restore earnings, cash flow, and liquidity to healthier levels.[4]

Even a high double-B rating places Avista in the same category as speculative, or "junk" bond issues.

B. Electric Power Industry

Q. What are the general conditions in the electric power industry?

A. For almost twenty years, lower fuel costs, inflation, and interest rates have provided electric utilities and their consumers a respite from the rapidly escalating electricity prices of the late 1970s and early 1980s. More recently, however, these general economic factors have been overshadowed by structural changes in the electric utility industry resulting from market forces, decontrol initiatives, and judicial decisions.

Q. Please describe these structural changes.

A. Competition is being increasingly promoted at the federal and state levels. The National Energy Policy Act of 1992, which reformed the Public Utility Holding Company Act of 1935, greatly increased prospective competition for the production and sale of power at the wholesale level. In April 1996 FERC adopted Order No. 888, which mandated open access to the wholesale transmission facilities of jurisdictional electric

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[3] Standard & Poor's, "Avista Corp.'s Ratings Lowered, Off CreditWatch", *RatingsDirect* (October 10, 2001).

[4] Moody's Investors Service, "Moody's Downgrades Credit Ratings of Avista Corporation (Sr. Sec. To Baa3)", *Global Credit Research* (October 8, 2001).

utilities, and it more recently addressed improvements to the transmission system including the establishment of Regional Transmission Organizations in Order 2000.

While wholesale wheeling provides transmission-dependent electric utilities with additional energy supply options, it has also introduced new risks to participants in the wholesale power markets. As *Moody's* recognized:

> Companies throughout the natural gas and electric power sectors face an uncertain future as the utility industry undergoes restructuring and moves toward increased competition. The changes, in large part, stem from the efforts of the Federal Energy Regulatory Commission (FERC) that have introduced a greater measure of competition into the natural gas and electric power wholesale markets during the 1990s. Similar efforts underway or anticipated at the state level are already altering the fundamentals of the manner in which energy is bought and sold and moved to the retail customer.[5]

Policies affecting competition in the electric power industry vary widely at the state level, but over 25 jurisdictions have enacted some form of industry restructuring. As foreshadowed by Merrill Lynch in 1996, this process of industry transition has led to the disaggregating of many formerly integrated electric utilities into three primary components – generation, transmission, and distribution:

> The electric utility industry is in a monumental transition state at the current time. The transition is from a vertically integrated, monopoly industry to one that we expect to be very competitive and significantly restructured. We expect all utility customers to have competitive choices in the next 5-10 years. We expect companies to realign and/or disaggregate their businesses – some may exit the generation business, others may exit the distribution business – as well as merge to create larger companies. ...The risk profile of the electric utility industry is clearly reaching higher levels than it has experienced in the past and will further increase.[6]

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[5] Moody's Investors Service, *Special Comment*, p. 5 (April 1999).

[6] Merrill Lynch, *Electric Utilities Industry Report*, p. 3 (June 24, 1996).

More recently, however, industry restructuring received a setback when electricity prices in California (one of the first states to implement competition) skyrocketed and reliability suffered.

Q. What impact have events in California and the Western U.S. had on investors' risk perceptions for firms involved in the electric power industry?

A. In the mid-1990s, California saw itself ready to claim the forefront of utility deregulation; instead, inadequate power supplies, rising demand, and a failed market structure combined to produce a well-publicized energy crisis. *S&P* summarized the fallout from the California crisis in the fall of 2000:

> Persistent hot weather, a dearth of needed new generation capacity, rapid customer growth and usage, record natural gas prices and the consequent explosion in power prices to double and even triple normal prices in an extremely short time, are wreaking political havoc for state and federal officials. There has been a great deal of finger pointing and anger generated by the frustrated expectations for lower prices that competing generation suppliers would provide. Some argue that generators are holding back supply to take advantage of the extremely volatile and lucrative energy markets. Others contend that there simply is not enough energy to meet California's increasing electricity demands. Reduced import capabilities, due to strong economic and load growth both in the Northwest and Southwest, have also limited generation alternatives.
>
> While it is inevitable that electricity demand in California will exceed supply for the foreseeable future, California is still in a desperate search for an immediate fix to its pricing crisis.[7]

Besides causing regulators and legislators to re-evaluate their industry restructuring plans, the financial implications of the recent California experience have exposed the hidden risks facing all segments of the electric power industry. The massive debts owed by the state's utilities to banks, power producers, and other creditors have shattered their financial

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[7] Standard & Poor's, "The Calm in the Storm: California's Municipal Electric Utilities", *RatingsDirect* (September 28, 2000).

integrity. Earlier this year, investors watched bond ratings for the two largest utilities in the state drop from investment grade to "junk" status within a matter of weeks. The subsequent bankruptcy filing of Pacific Gas and Electric Company (PG&E) in April 2001 brought the uncertainties associated with today's power markets into sharp focus for the investment community. *S&P* commented on the continuing difficulties faced by investors caught up in the debacle:

> Indeed, since last summer, the company and its investors have experienced nothing but frustration – first with respect to stemming the drain of its financial resources by the malfunctioning wholesale power market before these resources finally ran dry and then with its attempts to recover these resources. As Chairman Glynn commented last Friday, the regulatory and political processes have failed us. On Monday, Standard & Poor's took one of the final downward rating actions remaining to be taken on PG&E. We downgraded the utilities senior unsecured debt rating to 'D' from 'CC' in light of the company's comments that it did not anticipate paying regularly scheduled interest on these obligations.[8]

While the case of PG&E represents an extreme example, there is every indication that investors' risk perceptions for electric utilities have shifted sharply upward as events in the Western U.S. have continued to unfold.[9]

Q. How have utilities in the Northwest, including Avista, been impacted by the crisis in California?

A. In a recent report entitled "Utilities in Western U.S. Feeling the 'California Effect'", *S&P* observed that *"California's energy problems have certainly reverberated throughout electric and gas utilities in the western U.S."*[10] Because California depends on

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[8] Standard & Poor's, "California Utilities Update", *RatingsDirect* (April 16, 2001).

[9] For example, Platts' *Electric Utility Week* (July 9, 2001) noted that the "crisis saps investor confidence" and that fallout from the financial deterioration of California's utilities had spread beyond the state as "investors have turned away, spooked by the political and regulatory climate".

[10] Standard & Poor's, "Utilities in Western U.S. Feeling the 'California Effect'", *Utilities & Perspectives*, p. 5 (October 15, 2001).

imports to meet approximately 25 percent of its electricity needs, the chaotic conditions within the state spilled over into neighboring power markets. In a report on public power companies, *S&P* noted that rapid increases in wholesale electric prices were not restricted to California:

> Unrest in Western power markets has not been confined to California. The Northwest is experiencing a similar escalation in power prices that has, in turn, placed pressure on public power entities in the region that purchase some of their power from the spot market.[11]

Apart from price pressure attributable to the crisis in California, declining reserve margins also impacted market volatility in the Northwest and tight supply conditions were compounded by a series of forced outages at fossil-fueled generating facilities. Power shortages and skyrocketing prices led Governor Gary Locke to declare a statewide energy alert in Washington in order to protect critical industries.

Higher fuel costs for thermal generation and extreme weather only added "fuel to the fire". Because of the lack of surplus generation, utilities have been forced to run older, less efficient gas-fired facilities, while new generation facilities also rely predominantly on natural gas. As a result, demand for natural gas increased while deliverability remained largely static.[12] Coupled with intensified heating needs due to record cold weather, this led to sharply higher fuel costs for gas-fired generating facilities. In addition, utilities in the Northwest, which depend heavily on hydroelectric generation, have also been saddled with the effects of record-setting low precipitation and environmental constraints. Reduced stream flows have curtailed hydroelectric output and caused many utilities to turn to the

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[11] *Standard & Poor's Corporation*, "Public Power Companies in Northwest Increase Rates Due to Low Water, Skyrocketing Prices", Infrastructure Finance, p. 1 (January 18, 2001).

[12] For example see "Incentives to Burn: How Federal Policies, Industry Shifts Created A Natural Gas Crunch", THE WALL STREET JOURNAL (January 3, 2001).

market for replacement power precisely when supply was short and prices were reaching record highs. *Moody's* noted the vulnerability associated with the Northwest's dependence on hydro resources:

> In the case of the Northwest region, because there is such a large dependence on hydroelectric power, companies can be especially vulnerable when precipitation levels are below normal and/or when winter weather is severely cold. Indeed, in much the same way that extended heat spells strained energy resources in the summer-peaking state of California and other parts of the West this past summer, below normal hydro-electric conditions in the Northwest has wreaked some havoc there. The low water conditions currently prevailing in the Northwest reduces the energy generating capabilities of the hydroelectric facilities, adding to the challenges that utility companies face in meeting the growing energy demands of their customers. This is especially so given the power shortages that currently prevail in California, which prevents the California utilities from sending power north during the winter as they have historically been able to do because of the strong transmission line interconnection that exists between the two regions. [13]

Q. How do these market conditions compare with power cost fluctuations previously faced by Avista?

A. Because of Avista's dependence on hydroelectric generation and the absence of a PCA in its Washington jurisdiction, it has always faced the uncertainties associated with year-to-year fluctuations in water conditions. Nevertheless, the degree of price volatility that participants in the Northwest power market have been forced to assume is unprecedented and bears no resemblance to fluctuations encountered in the past.[14] Given the sharp departure from anything resembling historical experience, these price changes were extraordinary and beyond any reasonable expectations of market participants.

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[13] *Moody's Investors Service*, "The Northwest Region's Energy Supply Situation", Special Comment, p. 4 (January 2001).

[14] For example, Avista noted in its original Petition for the deferral mechanism in Docket No. 99-UE-000972 that while historical monthly market prices over the last 15 years ranged from a low of 0.8¢ per kilowatt hour (kwh) to a high of 4.0¢ per kwh, monthly market prices during the Summer of 2000 reached 13.0¢ per kwh. Daily prices soared to 37.5¢ per kwh and hourly prices frequently spiked to 75.0¢ per kwh.

Q. Has Avista been unique in facing these challenges?

A. No. To varying degrees, utilities throughout the Western U.S. have been confronted with the difficult task of maintaining reliable service and financial integrity in a power market characterized by short supply and unprecedented price volatility. Of course, the most notable and well-publicized impact of the regional power crisis has occurred in California. In only a matter of months, inadequate power supplies, rising demand, and the legacy of a failed market structure combined to produce skyrocketing electric prices and rolling blackouts. The regional power crisis has reverberated well beyond California's borders. In Nevada, deferred power cost balances for Sierra Pacific Resources, which stood at $392 million as of June 30, 2001, prompted the Nevada Legislature to mandate recovery of these expenses.[15] Similarly, utilities throughout the Northwest have been forced to seek significant rate increases to recover rising fuel and purchased power costs.

Q. Why are dramatic fluctuations in power costs of particular importance for regulated utilities?

A. Unlike firms in the competitive market, which are largely free to raise prices and pass higher production costs on to consumers, electric utilities face regulatory limitations on their ability to adjust rates to reflect current market conditions. Even for the majority of electric utilities that have permanent fuel and purchased power adjustment mechanisms in place, there can be a significant lag between the time the utility actually incurs the expenditure and when it is recovered from ratepayers. The Value Line Investment Survey (*Value Line*) noted one example of this regulatory lag:

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[15] Standard & Poor's, "Sierra Pacific Resources Sells Equity to Support Balance Sheet", *RatingsDirect*, p. 1 (August 17, 2001).

> **A lag in the recovery of sharply higher power costs is hurting Sierra Pacific Resources.** Power prices in the West have soared since the second quarter of 2000, and until recently, SPR's two utilities lacked a mechanism for recovering these increases. The Nevada Commission has granted one, but it won't solve the utilities' problem right away. That's because the mechanism tracks power costs over a trailing 12-month period and because the amount by which the utilities can raise rates each month is capped.[16]

These risks are compounded for regulated utilities that have no PCA, such as Avista. While having no ability to alter conditions within the wholesale markets for fuel and purchased power, these utilities remain obligated to furnish a reliable supply of energy on demand and at fixed rates. The greater business risk implied by this exposure to changes in input prices becomes acute during times of crisis, as is evident from recent events in the West. The most extreme example of this exposure is exemplified by *Value Line's* report on PG&E Corporation earlier this year:

> **Since mid-2000, PG&E has incurred $6.6 billion in purchased power losses.** Because of the high price its Pacific Gas and Electric subsidiary has been paying for power and its inability to recoup the cost from ratepayers, PG&E and its utility have defaulted on commercial paper maturity payments. This led major rating organizations to lower the company's and its subsidiary's bonds to junk bond status.[17]

Similarly, the impact of abnormal power markets has also resulted in double-B credit ratings for Avista's unsecured debt.

Q. Please summarize the financial fallout of Avista's exposure to escalating purchased power costs.

A. The extreme and unprecedented volatility in the price of purchased power has taken a devastating toll on Avista's financial condition. In the fifteen months ended September 30, 2001, Avista spent over $190 million to supply energy to customers that it

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[16] *The Value Line Investment Survey*, p. 1758 (November 17, 2000).

[17] *The Value Line Investment Survey*, p. 1757 (February 16, 2001).

was unable to recover through rates. Because Avista has been forced to use cash flows from operations, various bank borrowings, and short- and long-term debt to fund these expenses, this has led to a sharp deterioration in Avista's financial condition and a severe liquidity crunch. Commercial banks have been highly reticent to extend financing for Avista's ongoing operations or fund new construction and counterparties that Avista relies on to meet its energy needs have been unwilling to transact business absent prepayments or other credit terms. As a result of protracted negative cash flows associated with funding customers' power needs, Avista's ability to access capital markets at reasonable cost has been severely constrained. Even as early as April 2001, when Avista issued $400 million in senior unsecured notes, investors required a risk premium of 500 basis points over prevailing Treasury yields, in addition to other restrictive covenants further limiting financial flexibility. As of mid-July 2001, the entire proceeds of the note offering had been used and Avista was forced to contemplate the specter of technical default absent its ability to obtain waivers of certain covenants under its lending agreements. The dramatic increase in Avista's credit risk also compromised approval of construction financing previously negotiated for Coyote Springs II, Avista's 280 MW gas-fired generation plant under construction in Oregon. The WUTC noted the precarious nature of Avista's finances in support of its decision to approve a temporary rate surcharge:

> *57.* We also have summarized the evidence showing that Avista's financial health has declined very rapidly. The situation has become critical even during the pendency of this proceeding. …
>
> *58.* Staff does not disagree and argues that "[t]here is no dispute that Avista is in an apparent cash "crunch." *Staff Brief at 15.* Staff acknowledges that unless Avista obtains waivers from its bankers, it "may soon be in technical default on its $400 million credit line." *Id.* Mr. Schooley testified that "if investors are unwilling to provide funds, Avista may not be able to adequately invest in the infrastructure needed to serve [its] customers." *Exhibit No. 401-T at 22.* Mr. Schooley testified that another risk is that Avista

may "only be able to issue debt at a higher interest rate level." Id. Either result is likely to be detrimental to customers.[18]

Q. What measures has Avista taken in response to its deteriorating finances?

A. First, Avista has taken a number of steps to mitigate the increased power costs, including increased operation of its thermal resources, locking in fixed-price purchases, and aggressively pursuing conservation and load curtailment programs. Management has undertaken aggressive actions to conserve cash resources by trimming operating costs and capital expenditures. Avista has significantly reduced its operating and capital budgets for the remainder of 2001 and 2002 and implemented a hiring freeze in an effort to maintain liquidity. In addition, 175 key managers have taken pay cuts through year-end and Avista is evaluating the sale of certain noncore assets to generate cash. In a further effort to reduce capital needs and enhance liquidity, Avista announced on October 24, 2001 that it will sell 50 percent of its interest in Coyote Springs II to Mirant Corporation. Avista has also decided to sell substantially all of the assets of Avista Communications and will no longer pursue further development of non-regulated generation projects.

Avista has also enlisted the support of regulators, with the WUTC granting approval of its request for deferred accounting treatment in August 2000 and, more recently, a 25 percent rate surcharge in September 2001. As the WUTC recognized in approving a temporary rate surcharge:

> Our decision today is made necessary by extraordinary circumstances. In short, western wholesale power markets have exhibited, over the past eighteen months, prices and price volatility that are unprecedented in anyone's experience. Regulation of those markets at the federal level has been too

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[18] Washington Utilities and Transportation Commission, Docket No. UE-010395, *Sixth Supplemental Order Rejecting Tariff Filing; Granting Temporary Rate Relief, Subject to Refund; and Authorizing and Requiring Compliance Filing* at 22.

> much focused on the promise of competition and too-little focused on the damage caused to utilities and their customers when markets go awry.

Q. Have regulatory uncertainties continued to hamper Avista's recovery?

A. Yes. Like some other utilities in the region, Avista anticipated that its actions to secure firm power supplies in response to higher prices would have allowed it to earn profits from surplus energy sales. Instead, price caps imposed by FERC, which took effect June 20, 2001 and are scheduled to run through October 2002, combined with a persistent drought, have largely removed this opportunity to recoup deferred power costs. As a result, while the California Department of Water Resources may benefit from FERC's actions, Avista has experienced a "double-whammy" due to the crisis in California.

Meanwhile, despite the WUTC's approval of an emergency rate surcharge to aid Avista in dealing with its liquidity crisis, investors continue to focus on future uncertainties and Avista's ultimate ability to recover past and prospective power costs. *S&P* commented on the significance of these regulatory risks in its explanation for Avista's lower credit ratings:

> The recently approved 25% rate surcharge in Washington state is expected to provide some relief to Avista in the form of much needed liquidity. However, the rate surcharge is much less that that requested by the company and will expire in 15 months (Dec. 31, 2002), a much shorter period than the 27 months requested by Avista. As part of the recent [WUTC] decision, Avista's ability to defer additional power costs in excess of rates will terminate on Dec. 31, 2001, creating further uncertainty as to the recovery of additional power cost deferrals. Avista plans to address the unrecovered deferred balances, the ability to defer additional power costs, and the ability to share power costs with ratepayers in the upcoming general rate case filing, which is to be submitted by Dec. 1, 2001. However, the WUTC may take up to 11 months to respond, thereby creating considerable uncertainty as to the final outcome. …The negative outlook reflects the challenges facing Avista in its effort to maintain adequate liquidity while ensuring the integrity of its electric utility

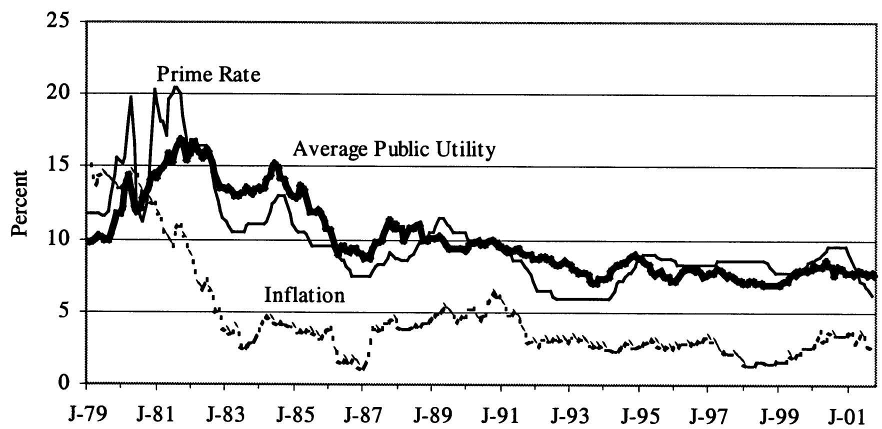
operations and the regulatory uncertainty concerning the company's upcoming general rate filing.[19]

Absent a constructive outcome in this proceeding, Avista's financial situation is sure to become increasingly perilous, which would ultimately impose even higher costs on all stakeholders.

C. Economy and Capital Markets

Q. What has been the pattern of interest rates during the 1980s and 1990s?

A. Average long-term public utility bond rates, the monthly average prime rate, and inflation as measured by the consumer price index since 1979 are plotted in the graph below. After peaking at 16.89 percent in September 1981, the average yield on long-term public utility bonds generally fell through 1986, reaching 8.77 percent in January 1987. Yields remained at or above 10 percent through mid 1989, gradually declined to 7 percent in October 1993, but then rose to 9 percent in November 1994. Interest rates then began a general decline, with the average public utility bond yield being 7.64 percent in October 2001:



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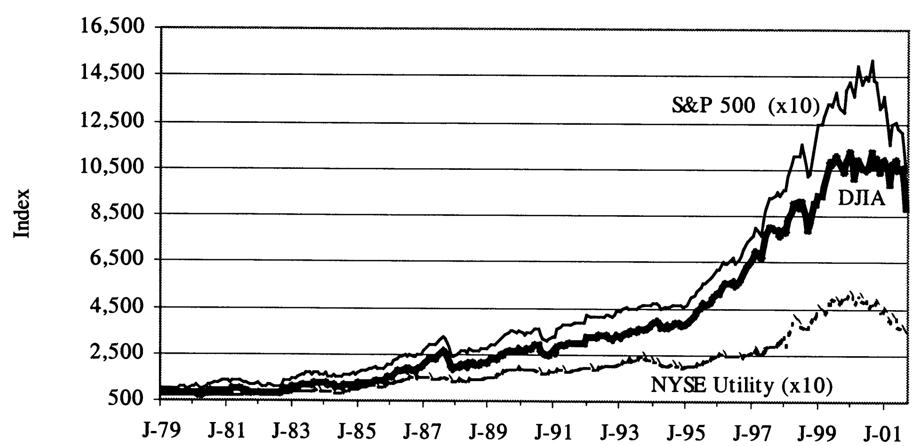
[19] Standard & Poor's, "Avista Corp.'s Ratings Lowered, Off CreditWatch", *RatingsDirect*, p. 2 (October 10, 2001).

Q. How has the market for common equity capital performed over this same period?

A. The past 20 years have witnessed the longest bull market in U.S. history, which is generally attributed to low inflation and interest rates, sustained economic growth, a favorable business climate, and widespread merger and acquisition activity. While common stocks have increased over ten times in value since 1979, valuations, particularly for firms in high technology industries, have fallen considerably since the first quarter of 2000. At the same time, the market has become increasingly volatile, with share prices repeatedly changing in full percentage points during a single day's trading. The graph below plots the performances of the Dow-Jones Industrial Average, the *S&P* 500 Composite Index (*S&P 500*), and New York Stock Exchange Utility Index since 1979 (the latter two indices were scaled for comparability):



Although the general trend in stock prices obscures much of the daily and weekly volatility in the graph, these short-term swings have increased risks for participants in equity markets. As noted by *Value Line*, investors have also felt these uncertainties in once-stable utility stocks:

> Utility investors have had to endure much more stock volatility than usual for the industry during the past three months. At the start of this year, the Dow Jones utility index fell some 19% from the December 2000 peak.[20]

Q. What is the outlook for the U.S. economy and capital markets?

A. During the past decade, the U.S. economy has enjoyed the longest peacetime expansion in history. Monetary and fiscal policies resulted in modest inflation during this period, with unemployment rates falling to their lowest levels since the 1960s. A revolution in information technology, rising productivity, and vibrant international trade have all contributed to strong economic growth. However, even before the events of September 11, 2001, there were increasing signs that the economic expansion would not be sustainable. Concerns regarding the slowing pace of economic activity have been exemplified by the Federal Reserve's sequential lowering of interest rates. Uncertainties over the fragility of the economy have only been magnified in the aftermath of the recent terrorist attacks, which threaten to further undermine consumer confidence and contribute to global economic instability. These factors cause the outlook to remain tenuous, with persistent stock and bond price volatility providing tangible evidence of the uncertainties faced by the U.S. economy.

Q. How do these capital market uncertainties affect electric utilities?

A. For electric utilities, stalled economic growth will undoubtedly mean flat energy sales. Although the economic expansion may resume in 2002, conflicting economic indicators cause considerable uncertainties to persist. Additionally, the volatility of stock and bond prices and the uncertain course of interest rates creates significant financial risks for utilities that seek to raise capital to finance required plant additions. And while inflation and

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[20] Value Line Investment Survey, *Electric Utility (East) Industry*, p. 155 (March 9, 2001).

interest rates are now relatively low, any future increases would place additional pressure on the adequacy of existing service rates.

III. CAPITAL STRUCTURE AND COST OF DEBT AND PREFERRED

Q. What is the purpose of this section?

A. This section discusses the implications of the capital structure on risk and rate of return, and compares the capital structure used by Avista with those maintained by other electric utilities and against industry benchmarks. In addition, the costs applicable to the debt and preferred components of the capital structure are evaluated.

A. Principles

Q. What is the role of capital structure in setting a utility's rate of return?

A. A utility's capital structure reflects the mix of capital – debt, preferred, and common equity – used to finance its assets. The proportions of a utility's total capitalization attributable to each source of capital are typically used to weight the costs of debt and preferred securities, and rate of return on common equity, in calculating an overall rate of return.

Q. Why does this weighting matter?

A. The capital structure ratios determine how much weight is given to a particular source of capital. Since the costs of debt and preferred securities and the rate of return on common equity are not the same, this affects the weighted average cost, or overall rate of return, of all sources of capital.

Q. Why are the costs of debt and preferred securities, and the rate of return on common equity, not the same?

A. The reason for this difference is that debt, preferred, and common equity have different characteristics, which cause investors to demand a higher rate of return to invest in the common stock of a utility versus loan it money in the form of debt or preferred securities.

When investors loan money in the form of debt (e.g., bonds), they enter into a contract whereby the utility agrees to pay the bondholders a specified amount of interest and to repay the principal of the loan in full. The bondholders have a senior claim on available cash flow for these payments, and if the utility fails to make them, they may force it into bankruptcy and liquidation for settlement of unpaid claims. Similarly, when the utility sells investors preferred stock, the utility promises to pay preferred stockholders specified dividends and, typically, to retire the preferred stock on a predetermined schedule. While the rights of preferred shareholders to available cash flow for these payments are junior to creditors, and preferred stockholders cannot compel bankruptcy, their claims are senior to those of common shareholders.

The last in line are common shareholders, the residual owners of the utility. They only receive cash flows, if any, that remain after all other claimants – employees, suppliers, governments, lenders, and preferred stockholders – have been paid. Therefore, the greater number of investors (i.e., bondholders and preferred stockholders) who have a prior claim on the utility's earnings, the greater the risk to common shareholders. For investors to be willing to bear this additional risk, they require a higher rate of return than lenders and preferred stockholders who have more certain, senior claims on the cash flows of the utility.

Q. Why doesn't a utility finance itself entirely with debt or preferred securities, since these are less expensive sources of capital?

A. If a utility were to attempt to finance itself with 100 percent debt or preferred securities, then there would be no common shareholders. The lenders or preferred stockholders would effectively become the residual owners of the utility, and since they would be exposed to the same risks as if they were common shareholders, they would require a correspondingly higher rate of return as compensation. Accordingly, utilities are generally financed with a mix of debt, preferred securities, and common equity in an effort to produce the lowest overall cost of capital while, at the same time, permitting the utility to maintain its financial integrity and its ability to attract additional capital on reasonable terms.

Q. How does the use of greater amounts of debt affect the rates of return required by investors?

A. A higher debt ratio, or lower common equity ratio, translates into increased financial risk for all investors. A greater amount of debt, and preferred stock, means more investors have a senior claim on available cash flow, thereby reducing the certainty that each will receive his contractual payments. This, in turn, increases the risks to which lenders and preferred stockholders are exposed, and they require correspondingly higher rates of interest and dividends, respectively, for their risk bearing. From common shareholders' standpoint, higher debt and preferred stock ratios mean that there are proportionately more investors ahead of them, thereby increasing the uncertainty as to the amount of cash flow, if any, that will remain. Again, in accordance with the fundamental risk-return tradeoff principle to be discussed in greater detail later, common shareholders require a correspondingly higher rate of return to compensate them for bearing the greater financial risk associated with a lower common equity ratio.

Q. What implications does the transition to competition have for the capital structures maintained by utilities?

A. The heightened business risks imposed by the evolution to competitive markets will force utilities to adopt a more conservative financial posture if credit ratings are to be maintained, as Moody's noted:

> "The key issue," say the analysts in a recent special comment, "is that the competitive industries have much lower operating and financial leverage, and that utilities must streamline both in order to be effective competitors." Analysts say the utilities must do this in order to post stronger financial indicators and maintain their current ratings level...[21]

Accordingly, the challenges imposed by evolving structural changes in the industry imply that utilities will be required to incorporate relatively greater amounts of equity in their capital structures.[22]

B. Capital Structure Ratios

Q. What capital structure are you recommending for Avista in this proceeding?

A. The capital structure I am recommending to calculate Avista's overall rate of return is identical to that approved by the WUTC in Avista's most recent general rate case, Docket Nos. UE-991606. This capitalization is as follows:

Capital Component	% of Total
Short-term Debt	4.0%
Long-term Debt	45.0%
Trust Preferred Securities	7.5%
Preferred Stock	1.5%
Common Equity	42.0%
Total	100.0%

Using this capital structure, which was authorized by the WUTC in September 2000, should avoid undue controversy while helping to limit the issues that must be adjudicated in this

[21] Moody's Investors Service, *Credit Risk Commentary*, p. 3 (July 29, 1996).

[22] More recently, *Value Line* reported in its October 5, 2001 edition (p. 695) that the average common equity ratio for the firms in the electric utility industry is expected to increase from 40.5 percent in 2000 to 48.5 percent in 2004-2006.

proceeding. Moreover, as explained subsequently, the capitalization approved by the WUTC little more than a year ago continues to represent a conservative mix of capital sources from which to calculate Avista's overall rate of return..

Q. How can the reasonableness of the capital structure currently authorized for Avista be evaluated?

A. It is generally accepted that the norms established by comparable firms provide a valid benchmark against which to evaluate the reasonableness of a utility's capital structure. The capital structure maintained by stand-alone, publicly traded companies should reflect their collective efforts to finance themselves so as to minimize capital costs while preserving their financial integrity and ability to attract capital. Moreover, these industry capital structures should also incorporate the requirements of investors, both debt and equity, as well as the influence of regulators.

Q. What capitalization ratios are maintained by other electric utilities?

A. Schedule 1 displays capital structure data at year-end 2000 for the two groups of electric utilities used to estimate the cost of equity. As shown there, the permanent, long-term capitalization for the electric utility proxy group (page 1) was composed of 51.1 percent long-term debt, 2.7 percent preferred, and 46.2 percent common equity. For the *S&P* electric utilities, long-term debt and preferred accounted for 51.6 and 3.0 percent of total long-term capital, respectively, with the average common equity ratio being 45.4 percent. Incorporating the same 4.0 percent average short-term debt ratio approved by WUTC in Avista's last general rate case results in the average capital structure ratios for these two groups of other utilities summarized below:

Electric Utility Proxy Group

Capital Component	% of Total
Short-term Debt	4.0%
Long-term Debt	49.1%
Preferred Securities	2.6%
Common Equity	44.4%
Total	100.0%

S&P Electric Utilities

Capital Component	% of Total
Short-term Debt	4.0%
Long-term Debt	49.6%
Preferred Securities	2.9%
Common Equity	43.6%
Total	100.0%

Q. What capital structures are actually being authorized by regulatory agencies for electric utilities?

A. The common equity component of the capital structures authorized for electric utilities by regulatory commissions across the U.S. is followed by Regulatory Research Associates, Inc. (*RRA*) and published in its Regulatory Focus report.[23] The average authorized common equity ratios for electric utilities reported by *RRA* for the past five years are shown in the following table:

[23] Regulatory Research Associates, "Major Rate Case Decisions–January-June 2001", *Regulatory Focus*, p. 3 (July 5, 2001).

	Average Authorized Equity Ratio
1996	44.34%
1997	48.79%
1998	46.14%
1999	45.08%
2000	48.85%
Average	46.64%

As evidenced above, the average common equity component of the capital structure authorized for electric utilities ranged between 44.34 and 48.79 percent of total capital over this five-year period and averaged 46.64 percent. *RRA* reported that equity ratios for year-to-date 2001 averaged 46.35 percent.[24]

Q. How do these ratios compare with other widely cited financial benchmarks for electric utilities?

A. *S&P* routinely publishes financial ratio guidelines corresponding to specific bond ratings. Widely cited in the investment community, these ratios are viewed in conjunction with a utility's *business profile* ranking, which ranges from 1 (strong) to 10 (weak) depending on a utility's relative business risks. Thus, *S&P's* guideline financial ratios for a given rating category (e.g., single-A) vary with the business or operating risk of the utility. In other words, a firm with a *business profile* of "2" (i.e., relatively lower business risk) could presumably employ more financial leverage than a utility with a business profile assessment of "9" while maintaining the same credit rating. The average *business profile* ranking assigned to the firms in the electric utility proxy group and the *S&P* electric utilities is "5". S&P last published revised financial benchmarks in 1999, noting that:

> Standard & Poor's has created a single set of financial targets that can be applied across the different utility segments. These financial measures reflect

[24] *Id.*

> the convergence that is occurring throughout the utility industry and the changing risk profile of the industry in general.[25]

Consistent with these revised guidelines and an *S&P business profile* ranking of “5”, a utility would be required to maintain a ratio of total debt to total capital in the range of 41.5 to 47 percent in order to qualify for a single-A bond rating, or 47 to 55 percent for a triple-B credit.

Q. What is your conclusion regarding the reasonableness of the capital structure approved by the WUTC in Avista's last general rate case?

A. After incorporating the 4.0 percent short-term debt ratio approved by the WUTC in Avista's last general rate case, the capital structures maintained by the two reference groups of electric utilities are entirely consistent with the 42.0 percent common equity ratio authorized for Avista in September 2000. While the total debt ratio of 49.0 percent implied by the WUTC's capitalization exceeds *S&P's* 47 percent debt ceiling for a single-A bond rating, it is within the guideline range for triple-B rated debt. Finally, as noted above, authorized capital structures for electric utilities implied an average equity ratio over the most recent five years of 46.64 percent. Thus, the 42 percent common equity ratio approved by the WUTC for Avista falls below the range established by nationwide regulatory decisions. Accordingly, the capital structure authorized by the WUTC in Avista's last general rate case is a conservative mix of capital with which to calculate an overall rate of return.

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[25] Standard & Poor's, "Utility Financial Targets Are Revised", *Utilities & Perspectives*, p. 1 (June 21, 1999).

C. Cost of Debt

Q. What average cost is associated with Avista's long-term debt?

A. After giving effect to pro-forma adjustments, Avista's long-term debt outstanding totals approximately $1.14 billion. This balance is composed of secured medium term notes, pollution control bonds, medium term notes, and senior corporate notes, with the interest rates attributable to each specific issue being detailed in Schedule 2. Besides interest expense, Avista necessarily incurs various issuance-related costs in connection with securing debt capital. Although these costs are capitalized and amortized over the life of the corresponding debt issue, none is included in Avista's rate base or operating expenses. Pages 1 through 3 of Schedule 2 combines the annual interest cost for each series of debt outstanding with related issuance costs. After incorporating adjustments to reflect refinancing of maturing debt and the impact of Avista's recent downgrade on certain interest rates and insurance costs, this produced an average cost of long-term debt for Avista of approximately 8.77 percent. As shown on page 3 of Schedule 2, the effective cost of Avista's short-term credit line is 8.45 percent.

D. Cost of Preferred

Q. What preferred series does Avista have outstanding?

A. As shown on page 4 of Schedule 2, Avista currently has three series of preferred outstanding - a $35 million issue of cumulative preferred stock, as well as $60 million in Trust Originated Preferred Securities and $40 million in Floating Rate Capital Securities (together, the preferred securities). In addition, Avista expects to issue a further $100 million of preferred securities in early 2002 to provide additional capital and reduce debt leverage. As with its debt, Avista incurs issuance costs in connection with the sale of its preferred. As detailed in Schedule 2, including the amortization of these expenses along with the annual dividend cost on existing and new issues resulted in a cost rate of approximately 7.39 percent for the cumulative preferred stock and a weighted cost of preferred securities of 8.35 percent.

IV. CAPITAL MARKET ESTIMATES

Q. What is the purpose of this section?

A. In this section, capital market estimates of the cost of equity are developed for two benchmark groups of electric utilities. First, I examine the concept of the cost of equity, along with the risk-return tradeoff principle fundamental to capital markets. Next, I describe DCF analyses conducted to estimate the cost of equity for other electric utilities. Finally, I report the findings of risk premium analyses based on authorized and realized rates of return that served as a check on my DCF results.

A. Economic Standards

Q. What role does the rate of return on common equity play in a utility's rates?

A. The return on common equity serves to compensate shareholders for the use of their capital to finance the plant and equipment necessary to provide utility service. Investors are free to invest their funds wherever they choose, and they will commit money to a particular investment only if they expect it to produce a return commensurate with those from other investments with comparable risks. Competition for investor funds is intense, even for utilities. Moreover, the return on common equity is integral in achieving the sound regulatory, economic, and legal objectives of rates that are sufficient to: 1) fairly compensate capital investment in the utility, 2) enable the utility to offer a return adequate to attract new capital on reasonable terms, and 3) maintain the utility's financial integrity.

Q. How is a fair rate of return on common equity customarily determined?

A. Unlike debt capital, there is no contractually guaranteed return on common equity capital since shareholders are the residual owners of the utility. Nonetheless, common equity investors still require a return on their investment; with the cost of equity being the minimum "rent" that must be paid for the use of their money. This cost of equity typically serves as the starting point for determining a fair rate of return on common equity.

Q. What fundamental economic principle underlies this cost of equity concept?

A. The cost of equity concept is predicated on the notion that investors are risk averse, and will willingly bear additional risk only if they expect compensation for their risk bearing. In capital markets where relatively risk-free assets are available (*e.g.*, U.S. Treasury securities) investors can be induced to hold more risky assets only if they are offered a premium, or additional return, above the rate of return on a risk-free asset. Since all assets compete with each other for investors' funds, more risky assets must yield a higher expected rate of return than less risky assets in order for investors to be willing to hold them.

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

$$k_i = R_f + RPi$$

where: R_f = Risk-free rate of return; and
RP_i = Risk premium required to hold more risky asset i.

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

Q. Is there evidence that the risk-return tradeoff principle actually operates in the capital markets?

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

To illustrate, the table below shows average yields during October 2001 on 20-year U.S. government bonds and on utility bonds of different ratings reported by *Moody's*. The data show that as risk (measured by progressively lower bond ratings) increases, the required rate of return rises. Also shown is the risk premiums over 20-year Treasury bonds for each bond-rating category:

Bond and Rating	**October 2001 Yield**	**Risk Premium Over Long-term Treasury**
U.S. Treasury - 20 Yr.	5.34%	
PublicUtility		
Aaa	7.45%	2.11%
Aa	7.47%	2.13%
A	7.63%	2.29%
Baa	8.02%	2.68%

Q. Does the risk-return tradeoff observed with fixed income securities extend to common stocks and other assets?

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

Q. Is this risk-return tradeoff limited to differences between firms?

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

Q. What does the above discussion imply with respect to estimating the cost of equity?

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

Q. What additional difficulties are associated with estimating current costs of equity in the electric power industry?

A. Estimating the cost of equity is difficult, even when comparable publicly traded companies are available. The ongoing restructuring of the electric power industry exacerbates the problems. Industry participants are in the midst of realigning their businesses, with many electric companies disaggregating along functional lines while others are aggressively expanding and diversifying their operations. *Moody's* noted that, because of market restructuring, it has become increasingly difficult to identify a peer group of firms that are directly comparable:

> The diverse strategies adopted in response to the deregulation of the US market have moved the industry from a peer group of 121 vertically integrated, regulated utilities, to 121 peer groups of one.[26]

Q. Did you rely on a single method to estimate the cost of equity for Avista?

A. No. Despite the theoretical appeal of or precedent for using a particular method to estimate the cost of equity, no single approach can be regarded as wholly reliable. As the Federal Communications Commission recognized:

> Equity prices are established in highly volatile and uncertain capital markets... Different forecasting methodologies compete with each other for eminence, only to be superceded by other methodologies as conditions change... In these circumstances, we should not restrict ourselves to one methodology, or even a series of methodologies, that would be applied mechanically. Instead, we conclude that we should adopt a more accommodating and flexible position.[27]

Therefore, while I rely primarily on the results of DCF models, I also corroborate my DCF results by reference to risk premium methods that focus specifically on electric utilities. In my opinion, comparing estimates produced by one method with those produced by other

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[26] Moody's Investors Service, *Electric Utilities Industry Outlook*, p. 4 (October 2000).

methods ensures that the estimates of the cost of equity pass fundamental tests of reasonableness and economic logic.

B. Discounted Cash Flow Analyses

Q. How are DCF models used to estimate the cost of equity?

A. The use of DCF models is essentially an attempt to replicate the market valuation process that sets the price investors are willing to pay for a share of a company's stock. The model rests on the assumption that investors evaluate the risks and expected rates of return from all securities in the capital markets. Given these expected rates of return, the price of each stock is adjusted by the market until investors are adequately compensated for the risks they bear. Therefore, we can look to the market to determine what investors believe a share of common stock is worth. By estimating the cash flows investors expect to receive from the stock in the way of future dividends and capital gains, we can calculate their required rate of return. In other words, the cash flows that investors expect from a stock are estimated, and given its current market price, we can "back-into" the discount rate, or cost of equity, that investors presumptively used bidding the stock to that price.

Q. What market valuation process underlies DCF models?

A. DCF models are derived from a theory of valuation which posits that the price of a share of common stock is equal to the present value of the expected cash flows (i.e., future dividends and stock price) that will be received while holding the stock, discounted at investors' required rate of return, or the cost of equity. Notationally, the general form of the DCF model is as follows:

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[27] FCC, Report and Order 42-43 (CC Docket No. 92-133) (evaluating methods used to prescribe rates of return for telephone companies) (1995).

$$P_0 = \frac{D_1}{(1+k_e)^1} + \frac{D_2}{(1+k_e)^2} + \cdots + \frac{D_t}{(1+k_e)^t} + \frac{P_t}{(1+k_e)^t}$$

where: P_0 = Current price per share;
P_t = Expected future price per share in period t;
D_t = Expected dividend per share in period t;
k_e = Cost of equity.

That is, the cost of equity is the discount rate that will equate the current price of a share of stock with the present value of all expected cash flows from the stock.

Q. Has this general form of the DCF model customarily been used to estimate the cost of equity in rate cases?

A. No. In an effort to reduce the number of required estimates and computational difficulties, the general form of the DCF model has been simplified to a "constant growth" form. But converting the general form of the DCF model to the constant growth DCF model requires a number of strict assumptions. These include:

- A constant growth rate for both dividends and earnings;
- A stable dividend payout ratio;
- The discount rate exceeds the growth rate;
- A constant growth rate for book value and price;
- A constant earned rate of return on book value;
- No sales of stock at a price above or below book value;
- A constant price-earnings ratio;
- A constant discount rate (i.e., no changes in risk or interest rate levels and a flat yield curve); and
- All of the above extend to infinity.

Given these assumptions, the general form of the DCF model can be reduced to the more manageable formula of:

$$P_0 = \frac{D_1}{k_e - g}$$

where: g = Investors' long-term growth expectations.

The cost of equity (K_e) can be isolated by rearranging terms:

$$k_e = \frac{D_1}{P_0} + g$$

This constant growth form of the DCF model recognizes that the rate of return to stockholders consists of two parts: 1) dividend yield (D_1/P_0), and 2) growth (g). In other words, investors expect to receive a portion of their total return in the form of current dividends and the remainder through price appreciation.

Q. Are the assumptions underlying the constant growth form of the DCF model met in the real world?

A. In practice, none of the assumptions required to convert the general form of the DCF model to the constant growth form are ever strictly met. In some instances, where earnings are derived solely from stable activities, and earnings, dividends, and book value track fairly closely, the constant growth form of the DCF model may be a reasonable working approximation of stock valuation. However, in other cases, where the circumstances surrounding the firm cause the required assumptions to be severely violated, the constant growth DCF model may produce widely divergent and meaningless results. This is especially true if the firm's earnings or dividends are unstable, or if investors are expecting the stock price to be affected by factors other than earnings and dividends.

Q. How did you implement the DCF model to estimate the cost of equity for Avista?

A. As discussed earlier, Avista is a diversified energy services company and its operations and finances are significantly influenced by activities outside the electric power industry. In order to reflect the risks and prospects associated with Avista's jurisdictional utility operations, my DCF analyses focused on two reference groups of other electric utilities. Recognizing that Avista is requesting approval of a permanent PCA, the first electric utility proxy group was composed of electric utilities operating only in states that permit recovery of fuel and purchased power costs through an adjustment clause outside of the traditional rate case process. A recent *RRA* report surveyed regulatory jurisdictions nationwide to identify current policy with respect to supply cost and fuel expense recovery.[28] Based on the results of *RRA's* study and the business descriptions for the electric utilities covered by *Value Line*, those companies operating only in states that allow energy cost pass-through mechanisms were identified. *RRA's* study also ranked the progress of each jurisdiction toward electric industry restructuring using a 5-tier classification system:

> ...Tier 1 includes those states where retail access is in place, and Tier 5 includes states where no substantive restructuring activity is underway.[29]

Accordingly, in order to better reflect the risks associated with Avista's electric utility operations in Washington, only those companies operating in states with a restructuring tier of "4" or "5" were included.[30] Finally, companies with less that 50 percent of revenues from utility operations were eliminated, as were those utilities engaged in a major merger or acquisition, which tends to distort certain financial data (*e.g.*, stock prices), or firms that do not pay common dividends.

In addition, DCF analyses were also conducted for those firms included by *S&P* in its Electric Utilities group. Once again, I excluded companies engaged in a major merger or acquisition or firms that do not pay common dividends. These criteria resulted in the reference groups of electric utilities shown on Schedules 3 and 4. On average both *Moody's* and *S&P* rate these two groups of electric utilities single-A.

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[28] Regulatory Research Associates, Inc., "RECOVERY OF FUEL AND WHOLESALE POWER COSTS: WHO IS AT RISK AND WHO IS NOT?", *Regulatory Focus* (February 28, 2001).
[29] *Id.* at 2.

Q. How is the constant growth form of the DCF model typically used to estimate the cost of equity?

A. The first step in implementing the constant growth DCF model is to determine the expected dividend yield (D_1/P_0) for the firm in question. This is usually calculated based on an estimate of dividends to be paid in the coming year divided by the current price of the stock. The second, and more controversial, step is to estimate investors' long-term growth expectations (*g*) for the firm. Since book value, dividends, earnings, and price are all assumed to move in lock-step in the constant growth DCF model, estimates of expected growth are often derived from historical rates of growth in these variables under the presumption that investors expect these rates of growth to continue into the future. Alternatively, a firm's internal growth can be estimated based on the product of its earnings retention ratio and earned rate of return on equity. This growth estimate may rely on either historical or projected data, or both. A third approach is to rely on security analysts' projections of growth in a firm's book value, dividends, earnings, and stock price as proxies for investors' expectations. The final step is to sum the firm's dividend yield and estimated growth rate to arrive at an estimate of its cost of equity.

Q. How was the dividend yield for the two reference groups of electric utilities determined?

A. Estimates of dividends to be paid by each of these electric utilities over the next twelve months, obtained from *Value Line*, served as D_1. This annual dividend was then divided by the corresponding stock price for each utility to arrive at the expected dividend yield. The expected dividends, stock price, and resulting dividend yields for the firms in the

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[30] RRA assigned Washington to Tier 5, indicating that it is not involved in the process of restructuring

electric utility proxy group and *S&P* Electric Utilities are presented on the first pages of Schedules 3 and 4, respectively. As shown there, the average dividend yield for the electric utility proxy group was 5.2 percent while the dividend yield for the *S&P* Electric Utilities averaged 4.6 percent.

Q. What are investors most likely to consider in developing their long-term growth expectations?

A. In constant growth DCF theory, earnings, dividends, book value, and market price are all assumed to grow in lockstep and the growth horizon of the DCF model is infinite. But implementation of the DCF model is more than just a theoretical exercise; it is an attempt to replicate the mechanism investors used to arrive at observable stock prices. Thus, the only "*g*" that matters in applying the DCF model is that which investors expect and have embodied in current market prices.

While the uncertainties inherent with common stock make estimating investors' growth expectations a difficult task for any company, in the case of electric utilities, the problem is exacerbated due to the unsettled conditions associated with the ongoing restructuring of the electric power industry. As discussed earlier, industry participants are in the midst of realigning their businesses, with many electric companies disaggregating along functional lines while others are aggressively expanding and diversifying their operations. As noted by *S&P*:

> With increasing industry competition, utilities are beginning to break out of old paradigms and are seeking ways to differentiate themselves and create a competitive edge.[31]

(*Id.*).

[31] Standard & Poor's, "Technology: The Competitive Edge", *Utilities & Perspectives*, p. 1(January 5, 1998):

Electric utilities have begun to merge and acquire other domestic electric and/or gas utilities. While some are pursuing investments in unrelated areas, other major acquisitions have involved overseas electric utility activities.

Given that the electric power industry is becoming increasingly competitive, diversified, and consolidated, investors undoubtedly recognize that the future for electric utilities will not be an extension of the past, and that dividend policy will become increasingly conservative as competition in the industry becomes more pervasive.

Q. How are investors' growth expectations for electric utilities being affected by the ongoing structural changes in the industry?

A. As described earlier, the electric utility industry is in the midst of a major upheaval. Competition is being increasingly promoted at the federal and state levels, and as a result of deregulation and ensuing competition on both the supply and demand sides of the industry, electric utilities' traditional monopoly status is being eroded. The investment literature is replete with discussions of how the introduction of competition into the industry is beginning, and will continue, to impact electric utilities. The Association for Investment Management and Research (AIMR), with over 35,000 members in the investment profession, concluded early on that:

> Everything about the electric utility industry is undergoing a transformation. The basics of this industry are no longer valid, which means new analytical tools are needed to understand and to analyze electric utilities. Deregulation is redefining the environment in which the industry operates and creating new challenges for industry participants. Industry restructuring is affecting the valuation of electric utility securities, making investing in these securities more challenging today than ever before.[32]

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[32] Association for Investment Management and Research, "Deregulation of the Electric Utility Industry: An Overview", p. 1 (January 28, 1997)

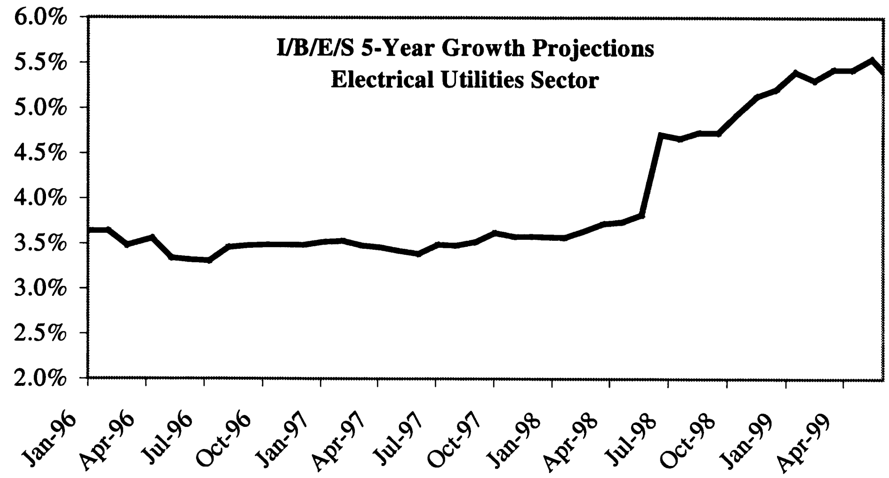
The transition of electric utilities to more competitive markets is affecting investors' expectations in a variety of ways, from the possibility of stagnant dividend growth in the near-term to prospects for higher growth in long-term earnings.

Q. Are growth rates based on past experience likely to be indicative of what investors expect from electric utilities in the future?

A. No. Investors are certainly aware that the pace of structural change varies between jurisdictions, with some states having already implemented retail competition (*e.g.,* New Jersey) while others remain under traditional regulation (*e.g.,* Washington). Nevertheless, over the longer-term investors clearly expect the industry to become increasingly competitive, diversified, and consolidated and they undoubtedly recognize that the future for electric utilities will not be an extension of the past. Growth expectations for electric utilities are clouded by the impact of increasing competition in the industry, but it is widely believed that once the constraints of regulation are relaxed and/or removed, the industry will achieve growth rates more closely paralleling those of competitive firms.

Q. What other evidence indicates that investors expect growth to accelerate for electric utilities?

A. While short-term projections are not likely to fully capture investors' long-term growth expectations once industry restructuring is completed, they have been trending upward as the transition to competition proceeds. The graph below plots the 5-year projected earnings growth rate for the Electrical Utilities sector reported monthly by I/B/E/S International, Inc. (*I/B/E/S*) for the period January 1996 through June 1999, when *I/B/E/S* changed the composition of the group:



Prior to 1998, projected earnings growth for electric utilities fell in a relatively narrow range and averaged approximately 3.5 percent. Since that time, the graph above clearly illustrates that, as restructuring in the electric utility industry has proceeded, near-term projected growth rates have risen steadily. This pattern is entirely consistent with an increase in investors' growth expectations as electric power markets are opened to competition.

Q. Are near-term dividend growth rates likely to provide a meaningful guide to investors' growth expectations for electric utilities?

A. No. Dividend policies for electric utilities have become increasingly conservative as competition in the industry has become more pervasive. In an article published by AIMR, Leonard S. Hyman, then Senior Industry Advisor with Smith Barney, Inc., noted that:

> Dividend payout as a percentage of reported net income for IOU's is almost twice as much as the S&P 400 industrials—78 percent versus 44 percent.[33]

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[33] Hyman, Leonard S., "Fearless Forecast: Electric Utilities in 2007", Association for Investment Management and Research, *Deregulation of the Electric Utility Industry*, p. 65 (January 28, 1997).

Mr. Hyman went on to conclude that:

> More than half of the industry's assets are tied up in generation, a business rapidly turning competitive. Whether utilities retain generating assets or not, they own them now. They require financial policies that meld regulated and competitive elements.[34] (p. 65)

Thus, while earnings may be expected to grow significantly, dividends have remained largely stagnant as utilities conserve cash to provide a hedge against heightened uncertainties and additional resources to expand their operations. As a result, focus has increasingly shifted from dividends to earnings as a measure of long-term growth. This change in investors' emphasis was noted by *Value Line*:

> Historically, investors have bought utility stocks because they offered much higher yields than most other equities...but dividends are no longer the sole focus. Investors and analysts are also paying attention to earnings, and price-earnings ratios...As the electric utility industry has been evolving into a less regulated (though not entirely deregulated) and more competitive business, so has investors' focus changed.[35]

More recently, *Barron's* noted that while electric utilities were *"once considered the province of risk-averse investors, they migrated last year into the hands of the growth-oriented crowd"*.[36] As a result, projected growth in earnings, which ultimately support future dividends and share prices, is likely to provide a more meaningful guide to investors' long-term growth expectations.

Q. What other evidence suggests that investors are more apt to consider trends in earnings in developing growth expectations?

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[34] *Id.*

[35] The Value Line Investment Survey, p. 1730 (February 19, 1999).

[36] Byrne, Harlan S., "Too Much Power? The utility industry's in a building boom. Why skeptics fear a bust", Barron's, p. 21 (August 6, 2001).

A. The importance of earnings in evaluating investors' expectations and requirements is well accepted in the investment community. As noted in *"Finding Reality in Reported Earnings"* published by AIMR:

> ...earnings, presumably, are the basis for the investment benefits that we all seek. "Healthy earnings equal healthy investment benefits" seems a logical equation, but earnings are also a scorecard by which we compare companies, a filter through which we assess management, and a crystal ball in which we try to foretell the future.[37]

Value Line's near-term projections and its Timeliness Rank, which is the principal investment rating assigned to each individual stock, are also based primarily on various quantitative analyses of earnings. As *Value Line* explained:

> The future earnings rank accounts for 65% in the determination of relative price change in the future; the other two variables (current earnings rank and current price rank) explain 35%.[38]

The fact that investment advisory services, such as *Value Line* and *I/B/E/S*, focus on projected growth in earnings indicates that the investment community regards this measure as a better indicator of future long-term growth than those based on historical data or other near-term projections. Nonetheless, near-term projections are apt to understate the long-run growth investors expect from the industry as regulation is removed and electric utilities' growth approaches that of other competitive firms.

Q. What are security analysts currently projecting in the way of earnings growth for the firms in the electric utility proxy group and the *S&P* Electric Utilities?

A. The earnings growth projections for each of the firms in the electric utility proxy group and the *S&P* electric utilities reported by *I/B/E/S* and published in *S&P's*

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[37] Association for Investment Management and Research, "Finding Reality in Reported Earnings: An Overview", p. 1 (December 4, 1996).

[38] The Value Line Investment Survey, *Subscriber's Guide*, p. 53.

Earnings Guide are displayed on page 2 of Schedule 3 and Schedule 4, respectively. Also presented are the EPS growth projections reported by Zacks Investment Research (*Zacks*), *Value Line*, and First Call Corporation (*First Call*). As shown on Schedule 3, these security analysts' projections resulted in the following average growth rates for the electric utility proxy group:

Electric Utility Proxy Group

Service	**Growth Rate**
I/B/E/S	7.2%
Zacks	7.2%
Value Line	8.6%
First Call	6.8%
Average	**7.5%**

Meanwhile, the average growth rates for the *S&P* Electric Utilities presented on page 2 of Schedule 4 resulted in an average projected growth rate of 8.8 percent:

S&P Electric Utilities

Service	**Growth Rate**
I/B/E/S	7.8%
Zacks	7.7%
Value Line	11.8%
First Call	7.9%
Average	**8.8%**

Q. How else are investors expectations of future long-term growth prospects often estimated for use in the constant growth DCF model?

A. In constant growth theory, growth in book equity will be equal to the product of the earnings retention ratio (one minus the dividend payout ratio) and the earned rate of return on book equity. Furthermore, if the earned rate of return and payout ratio are constant over time, growth in earnings and dividends will be equal to growth in book value. Although these conditions are seldom, if ever, met in practice, this approach may provide investors with a rough guide for evaluating a firm's growth prospects. Accordingly, conventional applications of the constant growth DCF model often examine the relationships between retained earnings and earned rates of return as an indication of the growth investors might expect from the reinvestment of earnings within a firm

Q. What growth rate does the earnings retention method suggest for the two reference groups of electric utilities?

A. The sustainable, "b x r" growth rates for each firm in the two benchmark groups are shown on the third page of Schedules 3 and 4, respectively. For each utility, the expected retention ratio (b) was calculated based on *Value Line's* projected dividends and earnings per share. Likewise, each firm's expected earned rate of return (r) was computed by dividing projected earnings per share by projected net book value. As shown there, this method resulted in an average expected growth rate for the electric utility proxy group of 6.3 percent, or 6.7 percent for the *S&P* Electric Utilities.

Q. What did you conclude with respect to investors' growth expectations for the two reference groups of electric utilities?

A. Based on the securities analysts' growth projections discussed above, I concluded that investors currently expect growth in the 7.0 to 8.0 percent range for the electric utility proxy group. For the S&P Electric Utilities, these projections implied an expected growth rate on the order of at least 8 percent.

Q. What do the structural changes in the industry imply with respect to security analysts' projections for electric utilities?

A. As discussed earlier, electric utilities are in the process of disaggregating and realigning their operations in response to industry restructuring. As a result, investors recognize that a large component of electric utilities' business will face risks and prospects akin to other firms in the competitive sector. In discussing the future growth prospects of

Duke Energy, for example, the company's chief risk officer noted that electric companies will offer investors the prospect of accelerated earnings growth to compensate for the additional risk that comes with being an energy merchant in competitive markets:

> "The business profile is higher risk," says [Richard] Osborne, but with it comes the hope of future 12% to 14% annual profit growth, instead of the 8% to 10% growth that Duke is projecting to analysts these days.[39]

While security analysts' near-term growth projections for electric utilities have risen in response to industry restructuring, are likely to understate investors' longer-term growth expectations for electric utilities once the transition to competition is completed.

Q. Is there anything else occurring in the electric power industry that might impact investors' growth expectations?

A. Yes. The prospect for continued merger and acquisition activity in the utility industry can distort the pricing mechanism presumed by the DCF model. As *Value Line* noted in a March 2001 report on CH Energy Group, Inc., the possibility of a merger can have a dramatic impact on a utility's stock price:

> **CH Energy stock is up nearly 10% since our last report,** three months ago. We attribute that to renewed takeover speculation, since CH Energy – the only electric company in the state that's not involved in merger and acquisition activity – is relatively small. We don't rule out such a possibility, especially if the company can't find attractive nonregulated companies for which it can use its cash hoard.[40]

Expectations of price appreciation that might be realized in the event of a merger, acquisition, or spin-off are not incorporated into the growth estimates used in the constant growth DCF model, but such growth is reflected in the share prices of electric utilities.

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[39] Wysocki, Jr., Bernard, "Soft Landing or Hard? Firm Tests Strategy on 3 Views of Future", WALL STREET JOURNAL at A1, A6 (July 7, 2000).

[40] The Value Line Investment Survey, p. 158 (emphasis in original) (March 9, 2001)

These factors both suggest that estimates of investors' actual growth expectations are biased downward, which leads to an understatement of the cost of equity.

Q. This notwithstanding, what cost of equity was implied for these two groups of electric utilities using the DCF model?

A. Combining the 5.2 percent average dividend yield with a representative growth rate range of 7.0 to 8.0 percent implied a cost of equity for the electric utility proxy group in the range of 12.2 to 13.2 percent. Meanwhile for the *S&P* Electric Utilities, adding their average dividend yield of 4.6 percent with the 8.0 percent growth rate discussed earlier produced an implied cost of equity of at least 12.4 percent. Based on the analyses described above, I concluded that investors' required rate of return on common equity for these electric utilities is presently on the order of 12.0 to 13.0 percent.

C. Risk Premium Analyses

Q. What other analyses did you conduct to estimate the cost of equity?

A. I also evaluated the cost of equity using risk premium methods. Because the cost of equity is inherently unobservable, no single method should be considered a solely reliable guide to investors' required rate of return. My applications of the risk premium method employ alternative approaches to measure equity risk premiums, encompass several periods and sample groups of companies, and include data through the present.

Q. Briefly describe the risk premium method.

A. The risk premium method of estimating investors' required rate of return extends to common stocks the risk-return tradeoff observed with bonds. The cost of equity is estimated by first determining the additional return investors require to forgo the relative safety of bonds and to bear the greater risks associated with common stock, and by then adding this equity risk premium to the current yield on bonds. Like the DCF model, the risk premium method is capital market oriented. However, unlike DCF models, which indirectly impute the cost of equity, risk premium methods directly estimate investors' required rate of return by adding an equity risk premium to observable bond yields.

Q. How did you implement the risk premium method?

A. The actual measurement of equity risk premiums is complicated by the inherently unobservable nature of the cost of equity. In other words, like the cost of equity itself and the growth component of the DCF model, equity risk premiums cannot be calculated precisely. Therefore, equity risk premiums must be estimated, with adjustments being required to reflect present capital market conditions and the relative risks of the groups being evaluated.

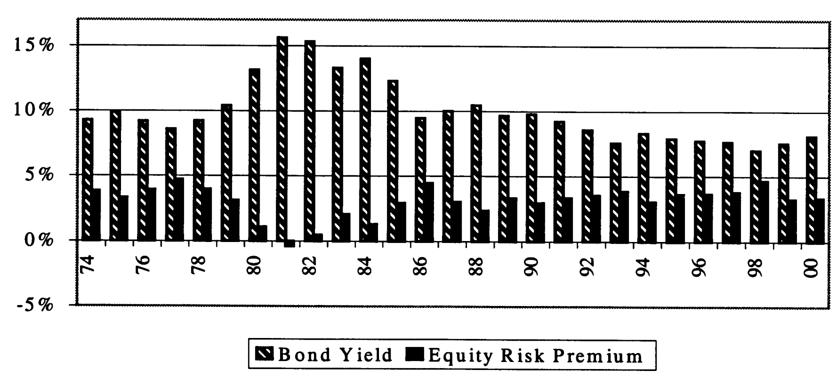
I based my estimates of equity risk premiums for electric utilities on (1) surveys of previously authorized rates of return on common equity, and (2) realized rates of return. Authorized returns presumably reflect regulatory commissions' best estimates of the cost of equity, however determined, at the time they issued their final order, and the returns provide a logical basis for estimating equity risk premiums. Under the realized-rate-of-return approach, equity risk premiums are calculated by measuring the rate of return (including dividends, interest, and capital gains and losses) actually realized on an investment in common stocks and bonds over historical periods. The realized rate of return on bonds is then subtracted from the return earned on common stocks to measure equity risk premiums.

Q. How did you implement the risk premium approach using surveys of allowed rates of return?

A. While the purest form of the survey approach would involve asking investors directly as to the additional return above interest rates they require to compensate for the additional risks of common equity, surveys of previously authorized rates of return on common equity are frequently referenced as the basis for estimating equity risk premiums. The rates of return on common equity authorized electric utilities by regulatory commissions across the U.S. are compiled by *RRA* and published in its *Regulatory Focus* report. In Schedule 5, the average yield on public utility bonds is subtracted from the average allowed rate of return on common equity for electric utilities to calculate equity risk premiums for each year between 1974 and 2000. Over this period, these equity risk premiums for utilities averaged 3.05 percent, and the yield on public utility bonds averaged 9.97 percent.

Q. Is there any risk premium behavior that needs to be considered when implementing the risk premium method?

A. Yes. Although the realized rate of return method assumes that equity risk premiums are constant over time, there is considerable evidence that the magnitude of equity risk premiums is not constant and that equity risk premiums tend to move inversely with interest rates. In other words, when interest rate levels are relatively high, equity risk premiums narrow, and when interest rates are relatively low, equity risk premiums widen. To illustrate, the graph below plots the yields on public utility bonds (shaded bars) and equity risk premiums (solid bars) shown on Schedule 5:



The graph clearly illustrates that the higher the level of interest rates, the lower the equity risk premium, and vice versa. The implication of this inverse relationship is that the cost of equity does not move as much as, or in lockstep with, interest rates. Accordingly, for a 1-percent increase or decrease in interest rates, the cost of equity may only rise or fall, say, 50 basis points. Therefore, when implementing the risk premium method, adjustments may be required to incorporate this inverse relationship if current interest rate levels have changed since the equity risk premiums were estimated. Finally, it is important to recognize that, for an industry in transition like the utility sector, the historical focus of the risk premium studies almost certainly ensures that they fail to fully capture the risks investors perceive going forward as utilities' markets are opened to competition. As a result, they are likely to understate the cost of equity for a firm operating in today's electric power industry.

Q. What cost of equity is implied by surveys of allowed rates of return on equity?

A. As illustrated above, the inverse relationship between interest rates and equity risk premiums is evident. Based on the regression equation between the interest rates and equity risk premiums displayed at the bottom of Schedule 5, the equity risk premium for electric utilities increased approximately 45 basis points for each percentage point drop in the yield on average public utility bonds. As illustrated there, with the yield on average public utility bonds in October 2001 being 7.64 percent, this implied a current equity risk premium of 4.10 percent for electric utilities. Adding this equity risk premium to the October 2001 yield on single-A public utility bonds of 7.63 percent produces a current cost of equity of 11.73 percent.

Q. How did you apply the realized-rate-of-return approach?

A. Widely used in academia, the realized-rate-of-return approach is based on the assumption that, given a sufficiently large number of observations over long historical periods, average realized market rates of return will converge to investors' required rates of return. From a more practical perspective, investors may base their expectations for the future on, or may have come to expect that they will earn, rates of return corresponding to those realized in the past.

Stock price and dividend data for the electric utilities included in the *S&P 500* are available since 1946. Schedule 6 presents annual realized rates of return for these electric utilities in each year between 1946 and 2000. As shown there, over this 55-year period realized rates of return for these utilities have exceeded those on single-A public utility bonds by an average of 5.10 percent. As noted earlier, the realized-rate-of-return method ignores the inverse relationship between equity risk premiums and interest rates and assumes that equity risk premiums are stationary over time; therefore, no adjustment for differences between historical and current interest rate levels was made. Adding this 5.10-percent equity risk premium to the October 2001 yield of 7.63 percent on single-A public utility bonds produces a current cost of equity for electric utilities of 12.73 percent.

V. RETURN ON EQUITY FOR AVISTA

Q. What is the purpose of this section?

A. This section addresses the legal and economic requirements for Avista's rate of return on equity. It examines other factors properly considered in determining a fair rate of return, including Avista's relative investment risk, the impact of a PCA, and flotation costs. This section also discusses the regulatory policy reasons for avoiding a return on equity that is not sufficient to maintain Avista's financial integrity and ability to attract capital. Finally, this section presents my conclusions regarding the fair rate of return to be applied to the common equity component of Avista's capital structure.

A. Relative Risks

Q. Are the results of your various quantitative analyses directly applicable to Avista?

A. No. The cost of equity estimates the electric utilities developed in my testimony are predicated on the investment risk associated with the benchmark groups, which on average are rated single-A. Meanwhile, as noted earlier, Avista's senior debt is rated low triple-B, with the double-B ratings on its unsecured notes falling below investment grade. Because investors require a higher rate of return to compensate them for bearing more risk, the greater investment risk implied by Avista's bond ratings suggests that the cost of equity is correspondingly higher than for the single-A rated utility groups.

While Avista's senior debt ratings remain at the very bottom of the investment grade scale, the negative outlook assigned by the rating agencies puts investors on notice that, absent strong regulatory support, a downgrade to "junk" bond status could be forthcoming. There is a precipitous increase in risk associated with moving from investment grade bonds to below-investment grade bonds. *S&P* documented this in its description of its triple- and double-B rating categories:

> An obligation rated 'BBB' exhibits adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor meet its financial commitment on the obligation. Obligations rated 'BB', 'B', 'CCC', and 'C' are regarded as having significant speculative characteristics. 'BB' indicates the lowest degree of speculation and 'C' the highest. While such obligations will likely have some quality and protective characteristics, these may be outweighed by large uncertainties or major exposures to adverse conditions.[41]

Thus, bond rating differences within the investment grade range tend to reflect relatively modest gradations among fairly secure investments. Meanwhile, moving to below investment grade implies an altogether different risk plateau – one where even the firm's most senior debt is regarded as a speculative investment.

Q. What amount of additional return do investors require in order to bear the additional risks associated with Avista's relatively greater investment risk?

A. As indicated earlier in the table comparing current yields on bonds, investors currently require approximately 40 basis points more to hold average triple-B public utility bonds versus those rated single-A. While average yields for double-B utility bonds are not reported, corporate bond yield averages from *S&P* indicate that investors demand an additional premium of approximately 170 basis points to move from a bond rated triple-B to one rated "BB+".[42] Investors would undoubtedly require a significantly greater premium for bearing the higher risk associated with the more junior common stock of a utility with Avista's weakened credit ratings.

B. Impact of Proposed PCA

Q. Is it uncommon for regulators to allow purchased power and fuel cost recovery mechanisms for electric utilities?

A. No. Since the 1970's, when sharp spikes in energy prices led to significant unrecovered electric supply costs, adjustment mechanisms that enable utilities to implement rate changes to pass-through fluctuations in fuel costs have been widely prevalent. As electric utilities' reliance on purchased power grew, PCAs were generally expanded to include purchased power costs. *RRA's* recent study indicated that only 16 state jurisdictions do not currently have energy cost pass-through mechanisms in place, including 10 states that

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[41] Standard & Poor's, *Bond Guide*, p. 12 (October 2001).

[42] *Id.* at p. 3. Standard & Poor's reported average yields on triple-B and "BB+" industrial bonds for September 2001 of 8.18 percent and 9.87 percent, respectively.

have largely completed a transition to retail competition.[43] Of the 10 states where no substantive restructuring of the electric utility industry is underway, only two jurisdictions – Utah and Washington – have not established power cost adjustment clauses.[44]

Q. Do other utilities without a PCA generally face the same degree of exposure to power cost volatility experienced by Avista?

A. No. While the number of jurisdictions that permit PCAs has diminished as the electric utility industry transitions to competition, other utilities are better positioned to cope with the uncertainties of power cost volatility. Even with restructuring, many utilities have retained their generating assets. Since most electric utilities rely on fossil and nuclear generating capacity, they are able to insulate against price fluctuations by locking in the cost of fuel and related transportation through long-term supply contracts. In instances where the utility has divested its generation facilities altogether, exposure to wholesale price volatility has generally been mitigated by entering into purchased power contracts and by hedging arrangements. In addition, while restructuring may constrain the utility's ability to pass through fluctuations in power costs, it may convey offsetting benefits in the form of incentive returns or other advantages not available under conventional regulation.

Moreover, the risks imposed on Avista due to the unprecedented upheaval in western power markets have been exacerbated by its reliance on hydroelectric generation. While customers benefit from the lower cost of hydro power, during times of low precipitation Avista is forced to make up any shortfall through purchases of higher-cost electricity on the wholesale market. Because the spread between the marginal cost of hydroelectric power

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[43] Regulatory Research Associates, Inc., "RECOVERY OF FUEL AND WHOLESALE POWER COSTS: WHO IS AT RISK AND WHO IS NOT?", *Regulatory Focus*, p. 2 (February 28, 2001).
[44] *Id.*

(near zero) and the replacement energy Avista must purchase in the market is so large, the risk of exposure to market price volatility is magnified for Avista.

Q. Is there any evidence to suggest that the cost of equity estimates for the reference groups of electric utilities already compensate investors for the risks associated with Avista's current lack of a PCA, and the continued exposure to wholesale market volatility that entails?

A. No. The comparable groups of utilities used to estimate the cost of equity are not materially affected by the same conditions that Avista must face in the wholesale power markets. First, as discussed above, electric utilities generally face far less risk due to exposure to fluctuations in fuel and purchased power costs, even when operating in largely deregulated markets. Second, the criteria used to select the electric utility proxy group were specifically designed to yield only utilities operating in states that permit energy-cost pass-through mechanisms. As a result, these firms should be largely insulated from exposure to fluctuations in the cost of obtaining wholesale power supplies, including price variation for both fuel and purchased power. Moreover, none of the utilities included in the electric utility proxy group are located in the western U.S. Even if they remain exposed to certain risks associated with the recovery of wholesale power costs, the uncertainties arising from the unprecedented power cost volatility experienced in the West would not be reflected in the cost of equity estimates developed earlier. And in contrast to Avista's electric utility operations, which are exposed to the added risks imposed by year-to-year fluctuations in water conditions, the proxy groups referenced in estimating the cost of equity do not rely on hydroelectric generation to any significant extent.[45] Accordingly, while cost of equity estimates for the reference groups presumably include a risk premium commensurate with normal operating and business risks, they clearly do not compensate investors for bearing the much greater uncertainties associated with Avista's exposure to price volatility in wholesale power markets.

Q. Are investors likely to distinguish between the impact of deferred accounting treatment or temporary surcharges and a permanent PCA, such as that requested by Avista in this proceeding?

A. Yes. The regulatory treatment customarily afforded to deferred costs, such as those resulting from Avista's extreme purchased power costs, represents a temporary, one-time mechanism approved to address a specific abnormal event. Meanwhile, a permanent PCA that allows for comprehensive recovery of fuel and purchased power costs would imply lower ongoing earnings variability, and lower business risk, even under normal operating conditions. *S&P* recognized the distinction between a temporary deferral mechanism and the ongoing benefits of a permanent PCA for Avista:

> In August 2000, the company was granted an accounting order to defer, for later recovery, purchased-power costs necessary to meet retail load needs. These costs can be deferred from July 1, 2000 until June 30, 2001. Although the accounting order provides some temporary relief, it has no immediate impact on cash flow.
>
> More importantly, however, on Oct. 2, 2000, the Washington Utilities and Transportation Commission (WUTC) rejected the company's application for an increase in electricity rates and a request for a power cost adjustment (PCA) mechanism. Both of these measures would have contributed readily to the improvement of Avista's weak financial profile.[46]

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[45] Based on a review of the business descriptions for the individual firms in the reference groups, as reported to investors by *Value Line* (August 17, September 7, & October 5, 2001).

[46] Standard & Poor's, "Research: Avista Corp.", *RatingsDirect*, p. 2 (December 29, 2000).

Similarly, *Value Line* also noted that, unlike a PCA adjustment, the accounting accrual of excess purchased power costs is not equivalent to collecting these amounts from ratepayers, observing that *"it's one thing for a utility to defer costs on its books, and another for it to recover them."*[47] While the rate surcharge approved by the WUTC does address Avista's liquidity crunch to some degree by generating cash through higher service rates, investors are aware that this is a temporary mechanism designed to address an immediate crisis. Without approval of an effective PCA, Avista will remain exposed to the risks of fluctuating power costs and the potential for continued price volatility in wholesale markets.

Q. Given the reduction in business risk associated with a permanent PCA, what would be the expected impact on investors' required rate of return?

A. Considering the ability of a permanent PCA to moderate ongoing earnings variability caused by fluctuations in weather and purchased power costs, it would undoubtedly lead to a reduction in the investment risk of the utility. In turn, this would imply a cost of equity below the level that fully reflects the risks of normal fluctuations in power supply costs. However, determining the impact of a permanent PCA on investors' required rate of return is problematic because, as noted earlier, the cost of equity itself is unobservable and there is no way to apportion the total risk premium between the numerous factors that contribute to a utility's total investment risk.

Q. Has the impact of a PCA on investors' required rate of return on equity been addressed by other witnesses in previous cases before the WUTC?

A. Yes. In a 1992 case involving Puget Sound Power & Light Company, both Dr. Richard J. Lurito, on behalf of the Commission Staff, and Mr. Stephen Hill, on behalf of

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[47] The Value Line Investment Survey, p. 1749 (February 16, 2001).

Public Counsel, testified that approval of the PRAM resulted in a 50 basis-point reduction in the cost of equity for Puget Sound Power & Light Company. As summarized by the WUTC:[48]

> Dr. Lurito calculated that PRAM has resulted in a 50-basis-point reduction in the cost of equity since Puget's last general rate case. ...Public Counsel contended the decoupling-type mechanism reduces volatility of revenue and income streams, therefore reducing risks. Public Counsel witness Stephen Hill calculated that this results in a cost of equity 50 basis points below that of similar utilities.

Q. What other factors are relevant to estimating the impact of a permanent PCA on investors required rate of return on equity?

A. While it is not possible to observe investors' actual cost of equity, observed yields on bonds of alternative ratings categories can provide one benchmark for the incremental change in investors' required return for a given change in risk. As discussed earlier, based on average bond yields for October 2001, investors currently require approximately 40 basis points less to hold average single-A public utility bonds versus those rated triple-B. However, because common equity is the most junior of a utility's securities, a given change in investment risk would have a greater impact on investors' required rate of return.

While the above adjustment relates to the change in risk associated with moving an entire ratings grade (e.g., triple-B to single-A), it is unlikely that a permanent PCA alone would be sufficient to result in an upgrade of this magnitude. While the bond rating agencies certainly recognize the importance of fuel and purchased power cost adjustments in reducing earnings volatility, it is only one of many factors considered by investors in evaluating a

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[48] *Eleventh Supplemental Order*, WUTC Docket No. UE-920433, et al., pp. 27-28 (September 21, 1993).

utility's total investment risk. For example, following the IPUC's approval of a PCA for Idaho Power in March 1993, Fitch noted that:[49]

> Adoption of this adjustment mechanism enhances credit quality by substantially reducing the impact of poor water years.

While Fitch cited the PCA's contribution to an improving credit trend, they elected to affirm, rather than increase, Idaho Power's bond ratings. Similarly, S&P also continued to assign an "A" rating to Idaho Power's senior debt.[50] More recently, although regulators in Nevada approved a mechanism to allow Sierra Pacific Resources to recover higher power costs, the company's credit rating has continued to decline. With respect to Avista specifically, while *S&P* made no mention of the possibility for substantially higher ratings if a PCA is approved, they put investors on notice that anything less than strong regulatory support would likely lead to a weaker financial profile and lower ratings.[51]

Second, any adjustment to the cost of equity presumes that the uncertainties of fluctuations in power supply costs have been considered in determining the utility's cost of capital. On the other hand, if investors' required rate of return has been estimated by reference to proxy utilities that are not exposed to significant supply cost uncertainty, the cost of equity will not fully reflect the additional risk attributable to the lack of a PCA. As discussed earlier, cost of equity estimates for the reference groups of electric utilities do not reflect the risks associated with the prospect of continued power market volatility in the West or the exposure to power cost uncertainty attributable to hydroelectric generation. Because they do not include compensation for these uncertainties, any shift in risk from shareholders

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[49] Dow Jones News Service, "Fitch-Idaho Power: Credit Trend Improving" (September 1, 1993).
[50] Standard & Poor's, *Global Sector Review: Utilities*, p. 64 (November 1995).
[51] Standard & Poor's, "Avista Corp.'s Ratings Lowered, Off CreditWatch", *RatingsDirect*, p. 2 (October 10, 2001).

to ratepayers attributable to Avista's requested PCA is already largely accounted for in my 12.0 to 13.0 percent cost of equity range. Accordingly, it would be a clear "double-dip" to make a further downward adjustment to a cost of equity that already does not compensate investors for exposure to the added volatility of fuel and purchase power costs faced by Avista. In fact, an offset to the cost of capital is not routinely associated with approval of a PCA.

Q. Given these considerations, what adjustment to the cost of equity might be considered in granting Avista a permanent PCA?

A. As discussed above, approval of a PCA alone is unlikely to result in a dramatic change in Avista's bond rating and there is no clear regulatory precedent for an offsetting adjustment to reduce the allowed rate of return. Moreover, the 12.0 to 13.0 percent cost of equity range determined earlier was established based on two groups of utilities that are largely immune to power cost volatility because of existing adjustment mechanisms, contractual arrangements, and the absence of significant hydroelectric generation. Taken together, these considerations indicate that any adjustment to Avista's cost of equity associated with approval of a permanent PCA should not exceed 50 basis points. As noted above, an adjustment on the order of 50 basis points is also consistent with past recommendations of witnesses for the WUTC Staff and Public Counsel.

Q. If the WUTC were to reject a PCA for Avista, would that have an impact on the cost of equity?

A. Most definitely. Denying Avista the ability to recover future power supply costs through a PCA would imply a dramatic increase in the relative investment risks of its jurisdictional electric utility operations. Considering the magnitude of the events that have transpired since the third quarter of 2000, investors' sensitivity to the uncertainties imposed by power market volatility has increased dramatically. Investors' sharpened focus on the risks associated with unrecoverable wholesale power costs was noted by *RRA*:

> The potential for volatility in wholesale power electricity markets, as highlighted by the temporary price spikes experienced in the Midwest in June 1999 and, more recently, by the ongoing severe capacity shortage/pricing crisis in California, has raised investors' level of awareness and concern with regard to the ability of electric utilities to recover increased wholesale power costs and fuel expenses from customers.[52]

Similarly, *S&P* noted that without a mechanism to regularly adjust rates, escalating commodity prices can create significant financial damage for retail service providers. *S&P* regards the lack of a PCA as one of the greatest impediments to financial stability:

> One of the most significant threats today to utilities' credit quality is uncertainty about the timely ability to pass power costs on to consumers. The issue for Standard & Poor's is this: To what lengths are regulators prepared to go to shelter ratepayers from the vagaries of the market and thereby threaten the financial strength of the utilities? Most utilities have been designated as the provider of last resort, or PLR. ...[T]he PLR obligation can potentially do some real damage to those incurring it. To preserve credit quality, these companies must be able to adjust rates not just to cover the cost of procuring power, but also to deliver the appropriate price signals to consumers.[53]

Without a PCA, Avista is forced to bear the risks of wholesale market competition while being obligated to provide reliable service irrespective of the associated costs to its shareholders. Unlike competitive firms that may choose to increase prices or withdraw from the market altogether, a utility operating under traditional regulation without the benefit of a PCA has little flexibility to accommodate fluctuations in power supply costs. Exposing Avista to the uncertainties of competitive wholesale markets while setting fixed retail prices

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[52] Regulatory Research Associates, "Recovery of Wholesale Power Costs: Who is at Risk and Who is Not?", *Regulatory Focus*, p. 1 (February 28, 2001).

[53] Standard & Poor's, "California Aside, Regulatory Support for Utility Credit Quality Remains Intact", *RatingsDirect*, p. 2 (July 13, 2001).

that fail to recover necessary costs would represent the worst of both the competitive and regulated paradigms.

Investors' required rates of return for utilities are premised on the regulatory compact that allows the utility an opportunity to recover reasonable and necessary costs. By sheltering utilities from exposure to extraordinary power cost volatility through a PCA, ratepayers benefit from lower capital costs than they would otherwise bear. Of course, the corollary implies that shifting the burden of extraordinary risks to shareholders would have the effect of considerably increasing the cost of equity to Avista and other utilities operating in Washington, with the end-result being a substantially greater cost of utility service throughout the state.

Q. What cost of equity would be implied for Avista if its request for a permanent PCA is rejected?

A. If the WUTC should elect to deny Avista's request for a PCA, a higher rate of return on equity would be required to compensate investors for bearing the greater risks of power market volatility. As explained earlier, without a PCA Avista will face continued exposure to potentially extreme fluctuations in power supply costs while remaining obligated to provide service at regulated rates. Given the investment community's increased sensitivity to such asymmetric risks, investors would undoubtedly find little to distiguish Avista's risks and prospects from unregulated wholesale generators or other firms operating in the competitive market. Accordingly, absent a PCA, expected rates of return for a competitive market benchmark such as the *S&P 500 Index* would represent one guide to investors' required rate of return on equity for Avista. The current dividend yield for the *S&P 500* is approximately 1.5 percent.[54] Combining this dividend yield with the average *I/B/E/S* growth rate for the firms in the *S&P 500* over the next five years of 15.4 percent results in a cost of equity estimate of 16.9 percent.[55] Denial of a PCA will almost certainly result in a further deterioration in Avista's already weak credit standing. Moreover, unlike firms in the competitive sector that have greater flexibility to respond to market changes, Avista's regulatory obligations will prevent it from passing higher costs on to consumers or withdrawing from uneconomic markets. Taken together, these factors suggest that the 16.9 percent cost of equity implied for the *S&P 500* is likely to understate investors' required rate of return for Avista in the event that its requested PCA is denied.

C. Flotation Costs

Q. What other considerations are relevant to setting the return on equity for Avista's electric and gas utility operations?

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

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[54] Standard & Poor's, *Index Services*, www.spglobal.com (as of October 31, 2001).

[55] The 15.4 percent growth rate is the average of the individual estimates for the firms included in the *S&P 500 Index*, as reported in *S&P's Earnings Guide* (August 2001).

While debt flotation costs are recorded on the books of the utility and amortized over the life of the issue, serving to increase the effective cost of debt capital, there is no similar accounting treatment to ensure that equity flotation costs are recorded and ultimately recognized. Even though there is no accounting convention to accumulate the flotation costs associated with past equity issues, flotation costs are a necessary expense of obtaining equity capital. Unless some provision is made to recognize these issuance costs, a utility's revenue requirements will not fully reflect all of the costs incurred for the use of investors' funds.

Q. How can flotation costs on past equity issues be recognized in revenue requirements?

A. Because there is no direct mechanism to recognize flotation costs associated with the issuance of common stock, they must be accounted-for indirectly. An upward adjustment to the cost of equity is the most logical mechanism to reflect these costs. Indeed, this is essentially how flotation costs incurred in connection with the issuance of preferred stock are generally recognized, since the cost of preferred stock is typically calculated by dividing annual preferred dividend requirements by the net proceeds from the sale of the preferred stock issue. By using net proceeds instead of face value as the denominator, flotation costs are recognized in the resulting cost of preferred stock.

Q. What is the magnitude of the adjustment to the "bare bones" cost of equity to account for flotation costs?

A. There are any number of ways in which a flotation cost adjustment can be calculated, with the adjustment ranging from just a few basis points to more than a full percent. For example, relating past flotation costs to total book common equity normally results in a nominal flotation cost adjustment of a few basis points. On the other hand, applying an average flotation cost expense percentage (i.e., 3 to 5 percent) to a utility's dividend yield, or its cost of equity, usually result in flotation cost adjustment between 15 and 50 basis points.

Q. Has the WUTC recognized that flotation costs are properly considered in setting the allowed rate of return on equity?

A. Yes. For example, in Avista's last general rate case the WUTC concluded that a flotation cost adjustment of 25 basis points should be included in the allowed return on equity:

> The Commission also agrees with both Dr. Avera and Dr. Lurito that a 25 basis point markup for flotation costs should be made. This amount compensates the Company for costs incurred from past issues of common stock. Flotation costs incurred in connection with a sale of common stock are not included in a utility's rate base because the portion of gross proceeds that is used to pay these costs is not available to invest in plant and equipment.[56]

D. Implications for Financial Integrity

Q. Why is it important to allow Avista an adequate rate of return on equity?

A. Given the social and economic importance of the electric utility industry, it is essential to maintain reliable and economical service to all consumers. While Avista remains committed to deliver reliable electric service at the lowest possible price, a utility's ability to fulfill its mandate can be compromised if it lacks the necessary financial wherewithal. Continuing to expose utility investors to the extraordinary risks associated with potential volatility in purchased power costs or linking recovery of reasonable and necessary costs with arbitrary reductions in the allowed rate of return on equity would send the wrong signal to investors. Because of the unrest in Western power markets, investors are already justifiably concerned regarding the impact on the financial integrity of the region's utilities. As S&P observed:

> Utilities with any degree of market purchase or natural gas exposure are feeling financial strain… Standard & Poor's expects that cash reserves particularly should be evaluated to determine whether they are sufficient to cover each utility's outstanding risk.[57]

The capital markets are well aware that cost deferral is not equivalent to cash in the bank and, with the extreme prices and regulatory uncertainty over potential under-recovery, maintaining liquidity has become increasingly important. In its recent review of the situation in the Northwest energy market, Moody's affirmed this concern:[58]

> …careful attention to ensure adequate liquidity, central to any good credit story, is heightened because unexpected increases in demand for capital can occur at any time when so much change is happening.

Q. What lessons can be learned from events in California?

A. The recent crisis in California provides a dramatic illustration of the high costs that all stakeholders must bear when a utility's financial integrity is compromised. As utilities have been forestalled from recovering the costs of the purchased power they are forced to buy to serve their customers and denied the opportunity to earn risk-equivalent rates of return, they have been cut off from access to capital. The state's economy has been jolted as cash-strapped utilities have been unable to buy enough wholesale power to avoid curtailments and rolling blackouts. Consumers have suffered the results of higher cost power and reduced reliability, which together threaten to strangle economic growth.[59] Moreover,

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[56] *Third Supplemental Order*, WUTC Docket No. UE-991606, et al., p. 95 (September 2000).

[57] *Standard & Poor's Corporation*, "Public Power Companies in Northwest Increase Rates Due to Low Water, Skyrocketing Prices", Infrastructure Finance, p. 2 (January 18, 2001).

[58] *Moody's Investors Service*, "The Northwest Region's Energy Supply Situation", Special Comment, p. 6 (January 2001).

[59] As The Economist reported in "California's Power Crisis: A state of gloom", p. 55 (January 20, 2001):

> *California's energy crisis could magnify the downside for the whole economy. In the end, the state's energy crisis could prove to be an unwanted wild card for the American financial markets and the global economy at large.*

while the impact of the utilities' deteriorating financial condition was felt swiftly, California stakeholders have discovered first hand how difficult and complex it can be to remedy the situation after the fact. As a recent article in THE WALL STREET JOURNAL recognized, the fallout from political, regulatory, and market failures will be felt by California residents for the foreseeable future:

> California officials, in essence, let the state's biggest utilities go broke and then ran through billions of dollars from the state general fund because they couldn't bring themselves to pass along actual costs to consumers. Now they're planning to issue $12.5 billion in bonds to spread those costs out over 15 years.[60]

Beyond the specific circumstances pertaining to events in the West, investors generally recognize that regulatory policy, for good reason, typically shelters utilities from extraordinary expenses beyond the control of management. For example, regulators routinely allow utilities to recover the costs associated with storms and other natural disasters without any offsetting reduction to the utility's cost of capital. The decision to realize such expenses if, and when, they occur recognizes that it is cheaper for ratepayers to bear these risks than to compensate investors in the form of higher, ongoing capital costs.

Q. What danger does an inadequate rate of return pose to Avista?

A. If Avista's return is set at a level that does not support investor confidence, the damage will not be easily reversible. Not only could service reliability be compromised, but once lost, investor confidence is difficult to recover. Consider the example of bond ratings. To restore a company's rating to a previous, higher level, rating agencies generally require the company to maintain its financial indicators above the minimum levels required for the higher rating. With Avista's senior debt ratings poised on the precipice between investment grade and junk bond status, the stakes associated with an inadequate rate of return have been increased dramatically.

In order to meet its funding requirements associated with the ongoing construction of Coyote Springs II and other capital requirements while attempting to improve its balance sheet and repair its financial profile, Avista must maintain access to capital on reasonable terms. Indeed, the WUTC recognized the importance to consumers of preserving Avista's financial wherewithal in its decision to grant a temporary rate surcharge:

> We cannot, and we will not, ignore the importance for customers of maintaining the financial stability of the Company.[61]

But the investment community remains less than enamored with the prospects for an equity position in Avista, as *Value Line* recently highlighted:

> **We see no reason to buy this stock.** There is too much regulatory uncertainty, earnings are weak (and very tough to call), and the dividend might even be at risk.[62]

Even with a gradual recovery of deferred costs through rate surcharges or other measures, investors remain focused on Avista's continued exposure to potential future power cost volatility. As S&P observed:

> ...[C]learly Avista needs a strong show of regulatory support in the form of a rate order that addresses the current cost under-recovery and provides a supportive regulatory framework that addresses the evolving and volatile nature of the electric utility industry. Without such a show of support, Standard & Poor's is concerned that Avista's financial profile may deteriorate further, leading to even weaker credit-protection measures.[63]

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[60] Smith, Rebecca, "The Lessons Learned", THE WALL STREET JOURNAL, p. R4 (September 17, 2001).

[61] *Sixth Supplemental Order*, WUTC Docket No. UE-010395, p. 3 (September 24, 2001).

[62] The Value Line Investment Survey, p. 1781 (November 16, 2001).

[63] Standard & Poor's, "Avista Corp.'s Ratings Lowered, Off CreditWatch", *RatingsDirect*, p. 2 (October 10, 2001).

Any actions that hinder efforts to bolster Avista's financial health or lead to further deterioration in bond ratings would ultimately impose significantly greater costs on consumers. *S&P* recognized the punitive cost associated with a utility's inability to maintain its credit standing:

> [W]hile the changes occurring the the U.S. utility market imply a greater level of risk, it should be noted that an important reason for maintaining investment-grade ratings is that the cost of doing business with other traders rises exponentially when the ratings fall below investment grade: counterparties require guarantees, letters of credit, and other forms of credit support that add significant costs to each trade, making the low-rated trader less competitive. So, companies that expect to remain in the game will likely do what is necessary to maintain a financial profile appropriate for at least a minimum investment grade rating.[64]

The cost of providing Avista an adequate return is small relative to both the potential benefits that a strong utility can have in providing reliable service and the extreme burden imposed by financial failure. Considering investors' heightened awareness of the risks associated with volatile wholesale power markets and the damage that results when a utility's financial flexibility is compromised, supportive regulation is perhaps more crucial now than at any time in the past.

D. Return on Equity Recommendation

Q. What then is your conclusion as to the fair rate of return on equity for Avista's jurisdictional electric utility operations?

A. As indicated earlier, based on the various capital market oriented analyses described in my testimony, I concluded that the "bare bones" cost of equity for a single-A rated electric utility is presently in the range of 12.0 to 13.0 percent. This "bare bones" cost of equity, however, does not recognize flotation costs incurred in connection with past sales of common stock. Accordingly, I added an adjustment of 25 basis points to this range to arrive at a fair rate of return on common equity range for of 12.25 to 13.25 percent. Considering the significantly greater investment risks implied by Avista's lower bond ratings and weakened financial measures, I concluded that investors would require a rate of return at least at the very top of this range, or 13.25 percent. Finally, because this return on equity was estimated by reference to proxy groups of other electric utilities that do not face the uncertainties associated with Avista's exposure to volatility in power supply costs, it already reflects the reduction in risk attributable to a power cost adjustment mechanism. Nevertheless, incorporating the maximum 50 basis-point downward adjustment to reflect Avista's requested PCA results in a fair rate of return on equity of 12.75 percent.

VI. OVERALL RATE OF RETURN

Q. What overall rate of return do you recommend be applied to the original cost invested capital of Avista?

A. I recommend that Avista be authorized an overall rate of return on rate base of 10.39 percent. As developed on Schedule 7, this overall rate of return is based on a capital structure consisting of 45 percent long-term debt, 4 percent short-term debt, 7.5 percent trust preferred securities, 1.5 percent preferred stock, and 42 percent common equity. This capital structure was combined with the average costs of debt and preferred discussed in Section III of my testimony and a fair rate of return on equity of 12.75 percent. If the WUTC should elect to deny Avista's request for a PCA, a higher rate of return on equity would be required to compensate investors for bearing the greater risks of power market volatility. Without a

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[64] Standard & Poor's, "Electric Utilities Explore New Strategies in Light of Deregulation", *RatingsDirect*, p. 2 (August 31, 2001).

PCA, Avista's credit ratings would undoubtedly fall firmly into "junk" bond territory and investors would be exposed to the risks of competitive power markets while assuming a continued obligation to provide reliable service at regulated prices. To compensate for bearing these asymmetrical risks, investors' required rate of return would likely exceed the 16.9 percent cost of equity indicated for the competitive firms in the *S&P 500.*

Q. Does this conclude your direct testimony in this case?

A. Yes, it does.

BEFORE THE WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION

DOCKET NO. UE-01_______

EXHIBIT NO. ____ (WEA-1)

WITNESS: WILLIAM E. AVERA, AVISTA CORP.

CAPITAL STRUCTURE

ELECTRIC UTILITY PROXY GROUP

	Sym	Company	Long-Term Debt	Preferred	Common Equity
1	CNL	Cleco Corp.	57.9%	2.4%	39.7%
2	FPL	FPL Group	40.6%	2.3%	57.1%
3	HE	Hawaiian Electric	58.4%	1.7%	39.9%
4	NI	NiSource	63.4%	1.4%	35.2%
5	PGN	Progress Energy	51.6%	0.8%	47.6%
6	SCG	SCANA Corp.	57.4%	2.3%	40.3%
7	SO	Southern Company	37.1%	12.3%	50.6%
8	TE	TECO Energy	47.7%	0.0%	52.3%
9	VVC	Vectren	45.8%	1.2%	53.0%
		Average	**51.1%**	**2.7%**	**46.2%**

Source: The Value Line Investment Survey (August 17, September 7, & October 5, 2001).

CAPITAL STRUCTURE

S&P ELECTRIC UTILITIES

	Sym	Company	Long-Term Debt	Preferred	Common Equity
1	AYE	Allegheny Energy	58.5%	1.7%	39.8%
2	AEE	Ameren Corp.	44.4%	3.8%	51.8%
3	AEP	American Elec. Pwr.	52.9%	2.7%	44.4%
4	CIN	Cinergy Corp.	50.2%	1.6%	48.2%
5	ED	Consolidated Edison	48.6%	2.3%	49.1%
6	CEG	Constellation Energy	48.6%	2.9%	48.5%
7	D	Dominion Resources	58.3%	2.8%	38.9%
8	DUK	Duke Energy	54.7%	1.1%	44.2%
9	PNW	Pinnacle West	45.1%	0.0%	54.9%
10	PGN	Progress Energy	51.6%	0.8%	47.6%
11	SO	Southern Company	37.1%	12.3%	50.6%
12	TXU	TXU Corp.	61.7%	6.9%	31.4%
13	XEL	Xcel Energy	58.8%	0.7%	40.5%
		Average	**51.6%**	**3.0%**	**45.4%**

Source: The Value Line Investment Survey (August 17, September 7, & October 5, 2001).

COST OF DEBT AND PREFERRED

Coupon Rate	Maturity Date	Principal Outstanding 09-29-1997	Effective Cost Rate	Annualized Cost
SECURED MEDIUM TERM NOTES, SERIES A				
6.25%	11-18-1999	5,000,000	6.335%	316,766
6.25%	11-23-1999	10,000,000	6.335%	633,533
6.28%	06-27-1998	5,000,000	6.368%	318,421
6.28%	07-08-1998	5,000,000	6.369%	318,431
6.32%	07-07-1998	15,000,000	6.409%	961,315
6.39%	07-07-2001	1,500,000	6.466%	96,985
6.67%	07-11-2006	5,000,000	6.737%	336,865
6.89%	06-03-2004	10,000,000	6.963%	696,323
6.95%	06-02-2004	10,000,000	7.024%	702,351
7.18%	08-10-2019	7,000,000	7.242%	506,910
7.26%	07-22-2014	5,000,000	7.326%	366,290
7.30%	08-10-2019	10,000,000	7.362%	736,231
7.37%	05-09-2008	7,000,000	7.437%	520,584
7.39%	05-10-2014	7,000,000	7.457%	521,962
7.44%	07-06-2019	1,000,000	7.503%	75,032
7.45%	06-10-2014	15,500,000	7.517%	1,165,118
7.53%	05-04-2019	5,500,000	7.600%	417,977
7.54%	05-04-2019	1,000,000	7.604%	76,038
7.90%	08-24-2002	4,000,000	7.982%	319,276
		129,500,000		9,086,408
SECURED MEDIUM TERM NOTES, SERIES B				
6.50%	11-27-2001	15,000,000	6.586%	987,947
6.50%	11-14-2001	5,000,000	6.586%	329,302
6.61%	06-27-1998	15,000,000	6.719%	1,007,822
6.67%	06-08-2001	5,000,000	6.757%	337,849
6.68%	06-08-2001	3,000,000	6.767%	203,011
6.90%	06-30-2006	5,000,000	6.972%	348,621
7.89%	08-24-2002	26,000,000	7.972%	2,072,685
		74,000,000		5,287,237
Annualized Amortization - Issuance and Loss/Reacq Expenses				1,881,420
TOTAL SECURED MEDIUM TERM NOTES		203,500,000		16,255,065
POLLUTION CONTROL BONDS				
6.000%	11-30-2019	4,100,000	6.340%	259,924
2.980%	09-30-2028	66,700,000	3.364%	2,243,672
2.950%	02-28-2030	17,000,000	3.340%	567,797
		87,800,000		3,071,394

COST OF DEBT AND PREFERRED

Coupon Rate	Maturity Date	Principal Outstanding 09-29-1997	Effective Cost Rate	Annualized Cost
MEDIUM TERM NOTES, SERIES A				
7.94%	01-21-2003	3,000,000	8.018%	240,545
8.01%	12-16-1997	8,000,000	8.102%	648,192
8.99%	04-30-1999	10,000,000	9.076%	907,648
		21,000,000		1,796,384
MEDIUM TERM NOTES, SERIES B				
6.75%	04-14-1999	5,000,000	6.837%	341,865
7.42%	08-08-2000	30,000,000	7.500%	2,249,933
7.90%	01-21-2003	9,000,000	7.978%	718,017
7.99%	02-02-2019	5,000,000	8.057%	402,833
8.01%	12-16-1997	2,000,000	8.102%	162,048
8.04%	12-16-1997	5,000,000	8.133%	406,626
8.05%	09-09-2008	12,000,000	8.127%	975,180
8.14%	12-17-2002	8,000,000	8.219%	657,524
8.15%	04-14-1998	10,000,000	8.243%	824,297
8.15%	09-14-2018	5,000,000	8.218%	410,884
8.23%	12-28-2018	5,000,000	8.298%	414,909
		96,000,000		7,564,116
MEDIUM TERM NOTES, SERIES C				
6.88%	06-04-2024	20,000,000	6.950%	1,389,955
6.37%	06-18-2024	15,000,000	6.417%	962,581
6.37%	06-18-2024	10,000,000	6.417%	641,720
5.99%	12-09-2003	14,000,000	6.078%	850,855
6.06%	12-09-2004	25,000,000	6.145%	1,536,146
8.02%	10-25-2006	25,000,000	8.107%	2,026,735
		109,000,000		7,407,991
MEDIUM TERM NOTES, SERIES D				
8.625%	08-31-1999	175,000,000	8.759%	15,328,726
8.000%	12-19-1997	45,000,000	8.157%	3,670,857
8.000%	12-19-1997	4,000,000	8.159%	326,362
		224,000,000		19,325,945
SENIOR CORP. NOTES, 9.75%				
9.750%	05-31-2004	400,000,000	10.301%	41,204,529
	Total Corporate Notes	400,000,000		41,204,529
Annualized Amortization - Issuance and Loss/Reacq Expenses				572,016
TOTAL MEDIUM TERM NOTES		850,000,000	9.161%	77,870,982
TOTAL LONG-TERM DEBT		1,141,300,000		97,197,440

AVISTA CORP.

COST OF DEBT AND PREFERRED

Coupon Rate	Maturity Date	Principal Outstanding 09-29-1997	Effective Cost Rate	Annualized Cost
PRO-FORMA ADJUSTMENTS				
Refinanced Debt Maturities (a)				
8.01%	12-16-1997	(8,000,000)	8.102%	(648,192)
8.01%	12-16-1997	(2,000,000)	8.102%	(162,048)
8.04%	12-16-1997	(5,000,000)	8.133%	(406,626)
8.000%	12-19-1997	(45,000,000)	8.157%	(3,670,857)
8.000%	12-19-1997	(4,000,000)	8.159%	(326,362)
		(64,000,000)		(5,214,084)
New Long-term Notes				
7.50%	11-30-2000	64,000,000	7.947%	5,085,895
Downgrade Impact - Pollution Control Bonds (b)				
2.980%	09-30-2028	(66,700,000)	3.364%	(2,243,672)
2.950%	02-28-2030	(17,000,000)	3.340%	(567,797)
		(83,700,000)		(2,811,470)
5.300%	09-30-2028	66,700,000	5.881%	3,922,671
5.450%	02-28-2030	17,000,000	6.192%	1,052,620
		83,700,000		4,975,291
Downgrade Impact - Other Long-term Debt (c)				
8.625%	08-31-1999	(175,000,000)	8.759%	(15,328,726)
9.125%	08-31-1999	175,000,000	9.260%	16,205,516
TOTAL PRO FORMA LONG-TERM DEBT		1,141,300,000	**8.77%**	100,109,861
SHORT-TERM DEBT				
Notes Payable - $220M Credit Line		125,000,000	5.418%	6,772,500
Commitment and Other Fees - Bank Line of Credit				1,875,026
TOTAL SHORT-TERM DEBT		125,000,000		8,647,526
PRO-FORMA ADJUSTMENTS				
Downgrade Impact (d)				
Notes Payable - $220M Credit Line		125,000,000	0.375%	468,750
Credit Facility Fees				1,452,103
TOTAL PRO FORMA SHORT-TERM DEBT		125,000,000	**8.45%**	10,568,379

(a) $64 million of debt to be retired and replaced with long-term debt at 7.5% with $0.75 million in issuance fees.

(b) Interest rate on Pollution Control Bonds increased to 5.3% and 5.45%. The insurance premium increased to $0.20 million with $0.60 million in issuance fees.

(c) Interest rate on $175 million in long-term debt increased by 0.5%.

(d) Increase in spread and credit facility fees to reflect impact of rating downgrade.

AVISTA CORP.

COST OF DEBT AND PREFERRED

Series	Amount Outstanding	Effective Cost Rate	Annualized Cost
TRUST PREFERRED SECURITIES			
7 7/8% TOPrS, Series A	60,000,000	8.740%	5,244,000
Floating Rate Capital Securities, Series B	40,000,000	6.490%	2,596,000
PRO FORMA ADJUSTMENTS			
New Issue	100,000,000	8.850%	8,850,000
TOTAL TRUST PREFERRED SECURITIES	200,000,000	**8.35%**	16,690,000
PREFERRED STOCK			
$6.950, Series K	35,000,000	**7.39%**	2,586,500

ELECTRIC UTILITY PROXY GROUP

EXPECTED DIVIDEND YIELD

	Sym	Company	(a) Stock Price	(b) Estimated Dividends Next 12 Mos.	Implied Dividend Yield
1	CNL	Cleco Corp.	$ 19.95	$ 0.89	4.5%
2	FPL	FPL Group	$ 53.59	$ 2.30	4.3%
3	HE	Hawaiian Electric	$ 37.69	$ 2.48	6.6%
4	NI	NiSource	$ 22.76	$ 1.24	5.4%
5	PGN	Progress Energy	$ 42.21	$ 2.18	5.2%
6	SCG	SCANA Corp.	$ 25.99	$ 1.25	4.8%
7	SO	Southern Company	$ 23.95	$ 1.34	5.6%
8	TE	TECO Energy	$ 25.96	$ 1.39	5.4%
9	VVC	Vectren	$ 21.34	$ 1.06	5.0%
		Average			**5.2%**

(a) Average stock price for the week ending November 2, 2001.
(b) Summary and Index, The Value Line Investment Survey (November 9, 2001).

ELECTRIC UTILITY PROXY GROUP

PROJECTED EARNINGS GROWTH

	Sym	Company	(a) IBES	(b) Zacks	(c) Value Line	(d) First Call
1	CNL	Cleco Corp.	10.0%	10.0%	8.0%	9.5%
2	FPL	FPL Group	7.0%	7.1%	4.5%	7.0%
3	HE	Hawaiian Electric	3.0%	5.0%	5.0%	3.0%
4	NI	NiSource	9.0%	8.0%	16.0%	7.0%
5	PGN	Progress Energy	7.0%	7.1%	NMF	7.0%
6	SCG	SCANA Corp.	5.0%	5.0%	6.5%	5.0%
7	SO	Southern Company	7.0%	5.2%	6.0%	5.0%
8	TE	TECO Energy	9.0%	9.3%	7.0%	9.0%
9	VVC	Vectren	8.0%	8.4%	15.5%	9.0%
		Average	**7.2%**	**7.2%**	**8.6%**	**6.8%**

NMF -- No Meaningful Figure.

(a) I/B/E/S International growth rates from Standard & Poor's Earnings Guide, (October 2001).
(b) Zacks Investment Research growth rates from www.my.zacks.com (November 12, 2001).
(c) The Value Line Investment Survey (August 17, September 7, & October 5, 2001).
(d) First Call growth rates from Yahoo!Finance (November 12, 2001).

ELECTRIC UTILITY PROXY GROUP

PROJECTED "B" x "R" GROWTH

	Sym	Company	(a) Proj. EPS	(a) Proj. DPS	(a) Proj. BVS	"b"	"r"	"b" x "r" Growth
1	CNL	Cleco Corp.	$2.00	$0.96	$14.25	14.0%	52.0%	7.3%
2	FPL	FPL Group	$5.25	$2.55	$33.50	15.7%	51.4%	8.1%
3	HE	Hawaiian Electric	$4.25	$2.32	$33.25	12.8%	45.4%	5.8%
4	NI	NiSource	$3.50	$1.60	$23.50	14.9%	54.3%	8.1%
5	PGN	Progress Energy	$4.80	$2.38	$36.90	13.0%	50.4%	6.6%
6	SCG	SCANA Corp.	$2.75	$1.45	$28.50	9.6%	47.3%	4.6%
7	SO	Southern Company	$2.05	$1.52	$13.90	14.7%	25.9%	3.8%
8	TE	TECO Energy	$2.50	$1.60	$16.00	15.6%	36.0%	5.6%
9	VVC	Vectren	$2.40	$1.19	$17.35	13.8%	50.4%	7.0%
		Average						**6.3%**

(a) The Value Line Investment Survey (August 17, September 7, & October 5, 2001).

S&P ELECTRIC UTILITIES

EXPECTED DIVIDEND YIELD

	Sym	Company	(a) Stock Price	(b) Estimated Dividends Next 12 Mos.	Implied Dividend Yield
1	AYE	Allegheny Energy	$ 36.53	$ 1.74	4.8%
2	AEE	Ameren Corp.	$ 40.08	$ 2.54	6.3%
3	AEP	American Elec. Pwr.	$ 42.35	$ 2.40	5.7%
4	CIN	Cinergy Corp.	$ 30.41	$ 1.80	5.9%
5	ED	Consolidated Edison	$ 38.60	$ 2.22	5.8%
6	CEG	Constellation Energy	$ 22.64	$ 0.48	2.1%
7	D	Dominion Resources	$ 61.25	$ 2.58	4.2%
8	DUK	Duke Energy	$ 38.29	$ 1.10	2.9%
9	PNW	Pinnacle West	$ 42.13	$ 1.60	3.8%
10	PGN	Progress Energy	$ 42.21	$ 2.18	5.2%
11	SO	Southern Company	$ 23.95	$ 1.34	5.6%
12	TXU	TXU Corp.	$ 46.23	$ 2.40	5.2%
13	XEL	Xcel Energy	$ 27.83	$ 1.50	5.4%
		Average			**4.6%**

(a) Average stock price for the week ending November 2, 2001.
(b) Summary and Index, The Value Line Investment Survey (November 9, 2001).

S&P ELECTRIC UTILITIES

PROJECTED EARNINGS GROWTH

			(a)	(b)	(c)	(d)
	Sym	**Company**	**IBES**	**Zacks**	**Value Line**	**First Call**
1	AYE	Allegheny Energy	9.0%	9.1%	14.5%	10.0%
2	AEE	Ameren Corp.	5.0%	4.0%	4.0%	5.0%
3	AEP	American Elec. Pwr.	6.0%	6.7%	35.5%	7.0%
4	CIN	Cinergy Corp.	6.0%	6.0%	6.0%	7.0%
5	ED	Consolidated Edison	4.0%	3.9%	2.5%	4.3%
6	CEG	Constellation Energy	10.0%	9.2%	12.0%	9.0%
7	D	Dominion Resources	10.0%	10.3%	20.0%	10.0%
8	DUK	Duke Energy	14.0%	12.4%	14.0%	13.0%
9	PNW	Pinnacle West	8.0%	8.7%	5.5%	9.0%
10	PGN	Progress Energy	7.0%	7.1%	NMF	7.0%
11	TE	Southern Company	7.0%	5.2%	6.0%	5.0%
12	TXU	TXU Corp.	8.0%	8.6%	6.0%	8.5%
13	XEL	Xcel Energy	7.0%	8.5%	15.0%	8.0%
		Average	**7.8%**	**7.7%**	**11.8%**	**7.9%**

(a) I/B/E/S International growth rates from Standard & Poor's Earnings Guide, (October 2001).
(b) Zacks Investment Research growth rates from www.my.zacks.com (November 12, 2001).
(c) The Value Line Investment Survey (August 17, September 7, & October 5, 2001).
(d) First Call growth rates from Yahoo!Finance (November 12, 2001).

S&P ELECTRIC UTILITIES

PROJECTED "B" x "R" GROWTH

			(a)	(a)	(a)			
	Sym	**Company**	**Proj. EPS**	**Proj. DPS**	**Proj. BVS**	**"b"**	**"r"**	**"b" x "r" Growth**
1	AYE	Allegheny Energy	$5.95	$1.88	$36.50	16.3%	68.4%	11.2%
2	AEE	Ameren Corp.	$3.75	$2.62	$28.25	13.3%	30.1%	4.0%
3	AEP	American Elec. Pwr.	$4.75	$2.40	$34.25	13.9%	49.5%	6.9%
4	CIN	Cinergy Corp.	$3.10	$1.88	$23.20	13.4%	39.4%	5.3%
5	ED	Consolidated Edison	$3.45	$2.28	$31.35	11.0%	33.9%	3.7%
6	CEG	Constellation Energy	$4.35	$0.54	$37.95	11.5%	87.6%	10.0%
7	D	Dominion Resources	$6.25	$2.58	$43.75	14.3%	58.7%	8.4%
8	DUK	Duke Energy	$4.00	$1.00	$27.00	14.8%	75.0%	11.1%
9	PNW	Pinnacle West	$4.30	$1.93	$39.25	11.0%	55.1%	6.0%
10	PGN	Progress Energy	$4.80	$2.38	$36.90	13.0%	50.4%	6.6%
11	TE	Southern Company	$2.05	$1.52	$13.90	14.7%	25.9%	3.8%
12	TXU	TXU Corp.	$4.45	$2.44	$39.65	11.2%	45.2%	5.1%
13	XEL	Xcel Energy	$3.25	$1.75	$22.75	14.3%	46.2%	6.6%
		Average						**6.7%**

(a) The Value Line Investment Survey (August 17, September 7, & October 5, 2001).

ANALYSIS OF AUTHORIZED RATES OF RETURN ON EQUITY FOR ELECTRIC UTILITIES

YEAR	(a) ALLOWED ROE	(b) AVERAGE PUBLIC UTILITY BOND YIELD	RISK PREMIUM
1974	13.10%	9.27%	3.83%
1975	13.20%	9.88%	3.32%
1976	13.10%	9.17%	3.93%
1977	13.30%	8.58%	4.72%
1978	13.20%	9.22%	3.98%
1979	13.50%	10.39%	3.11%
1980	14.23%	13.15%	1.08%
1981	15.22%	15.62%	-0.40%
1982	15.78%	15.33%	0.45%
1983	15.36%	13.31%	2.05%
1984	15.32%	14.03%	1.29%
1985	15.20%	12.29%	2.91%
1986	13.93%	9.46%	4.47%
1987	12.99%	9.98%	3.01%
1988	12.79%	10.45%	2.34%
1989	12.97%	9.66%	3.31%
1990	12.70%	9.76%	2.94%
1991	12.55%	9.21%	3.34%
1992	12.09%	8.57%	3.52%
1993	11.41%	7.56%	3.85%
1994	11.34%	8.30%	3.04%
1995	11.55%	7.91%	3.64%
1996	11.39%	7.74%	3.65%
1997	11.40%	7.63%	3.77%
1998	11.66%	7.00%	4.66%
1999	10.77%	7.55%	3.22%
2000	11.43%	8.09%	3.34%
Average		9.97%	3.05%

Regression Output	
Constant	0.07545
Std Err of Y Est	0.00576
R Squared	0.78863
No. of Observations	27
Degrees of Freedom	25
X Coefficient(s)	-0.45091
Std Err of Coef.	0.04669

Current Equity Risk Premium	
Avg. Yield over Study Period	9.97%
October 2001 Avg. Utility Bond Yield	7.64%
Change in Bond Yield	-2.33%
Risk Premium/Interest Rate Relationship	-45.09%
Adjustment to Average Risk Premium	1.05%
Average Risk Premium over Study Period	3.05%
Adjusted Risk Premium	**4.10%**

(a) Major Rate Case Decisions, Regulatory Focus, Regulatory Research Associates (January 24, 2001 & January 16, 1990); UtilityScope Regulatory Service, Argus (January 1986).

(b) Moody's Public Utility Manual (1999); Moody's Credit Perspectives (various editions).

ANALYSIS OF REALIZED RATES OF RETURN ON EQUITY
FOR THE S&P ELECTRIC POWER COMPANIES

	S&P ELECTRIC COMPANIES (a)			S&P SINGLE-A PUBLIC UTILITY BONDS (b)		
	CLOSE PRICE	DIV	ANNUAL REALIZED RETURN	CLOSE YIELD	PRICE	ANNUAL REALIZED RETURN
1945	$16.34			2.730%		
1946	$15.53	$0.73	-0.49%	2.719%	$100.18	2.91%
1947	$12.89	$0.75	-12.17%	3.037%	$94.87	-2.41%
1948	$12.37	$0.71	1.47%	3.048%	$99.82	2.86%
1949	$14.60	$0.80	24.49%	2.696%	$105.88	8.93%
1950	$14.49	$0.88	5.27%	2.814%	$98.05	0.75%
1951	$16.07	$0.92	17.25%	3.314%	$92.16	-5.03%
1952	$18.28	$0.95	19.66%	3.247%	$101.06	4.37%
1953	$18.97	$0.99	9.19%	3.331%	$98.68	1.93%
1954	$22.39	$1.03	23.46%	3.152%	$102.85	6.18%
1955	$24.06	$1.09	12.33%	3.394%	$96.23	-0.61%
1956	$23.61	$1.13	2.83%	4.186%	$88.60	-8.01%
1957	$24.85	$1.19	10.29%	3.968%	$103.20	7.39%
1958	$33.14	$1.24	38.35%	4.511%	$92.42	-3.61%
1959	$33.42	$1.30	4.77%	4.799%	$96.09	0.60%
1960	$39.35	$1.37	21.84%	4.635%	$102.26	7.06%
1961	$49.28	$1.44	28.89%	4.663%	$99.61	4.25%
1962	$48.60	$1.52	1.70%	4.330%	$104.73	9.39%
1963	$51.97	$1.63	10.29%	4.510%	$97.49	1.82%
1964	$58.21	$1.74	15.36%	4.468%	$100.59	5.10%
1965	$58.05	$1.90	2.99%	4.860%	$94.71	-0.82%
1966	$53.49	$2.04	-4.34%	5.606%	$90.59	-4.55%
1967	$49.90	$2.16	-2.67%	6.497%	$89.61	-4.78%
1968	$51.95	$2.27	8.66%	7.012%	$94.25	0.75%
1969	$42.65	$2.33	-13.42%	8.433%	$85.88	-7.11%
1970	$45.62	$2.40	12.59%	8.442%	$99.91	8.34%
1971	$44.18	$2.47	2.26%	7.704%	$107.78	16.22%
1972	$43.50	$2.53	4.19%	7.736%	$99.66	7.37%
1973	$32.85	$2.51	-18.71%	8.104%	$96.25	3.98%
1974	$22.03	$2.49	-25.36%	9.254%	$89.27	-2.63%
1975	$30.56	$2.57	50.39%	9.625%	$96.63	5.89%
1976	$35.17	$2.58	23.53%	8.366%	$112.58	22.21%
1977	$35.67	$2.74	9.21%	8.810%	$95.71	4.08%
1978	$31.38	$2.94	-3.78%	9.750%	$91.55	0.36%
1979	$28.44	$3.10	0.51%	11.470%	$86.31	-3.94%
1980	$27.19	$3.20	6.86%	13.394%	$86.48	-2.05%
1981	$29.33	$3.42	20.45%	15.663%	$86.06	-0.54%
1982	$36.15	$3.62	35.59%	12.206%	$126.20	41.86%
1983	$37.14	$3.84	13.36%	12.950%	$94.63	6.83%
1984	$42.26	$4.06	24.72%	12.394%	$104.16	17.11%
1985	$48.82	$4.15	25.34%	10.538%	$115.76	28.16%
1986	$58.31	$4.21	28.06%	9.120%	$113.37	23.90%
1987	$49.71	$4.34	-7.31%	10.090%	$91.49	0.61%
1988	$53.87	$4.37	17.16%	10.020%	$100.62	10.71%
1989	$66.55	$4.28	31.48%	9.360%	$106.11	16.13%
1990	$63.47	$4.45	2.06%	9.600%	$97.82	7.18%
1991	$77.25	$4.57	28.91%	8.930%	$106.41	16.01%
1992	$76.78	$4.68	5.45%	8.640%	$102.84	11.77%
1993	$81.71	$4.71	12.56%	8.740%	$99.03	7.67%
1994	$66.30	$4.65	-13.17%	8.680%	$100.59	9.33%
1995	$81.62	$4.67	30.15%	7.970%	$107.32	16.00%
1996	$76.75	$4.61	-0.32%	7.570%	$104.26	12.23%
1997	$91.49	$4.47	25.03%	7.070%	$105.55	13.12%
1998	$100.86	$4.39	15.04%	7.000%	$100.78	7.85%
1999	$77.42	$4.35	-18.93%	8.250%	$87.39	-5.61%
2000	$113.00	$4.42	51.67%	8.400%	$98.51	6.76%
AVERAGE 1946-2000			**11.18%**			**6.08%**

REALIZED RATE OF RETURN	
S&P ELECTRIC COMPANIES	11.18%
SINGLE-A PUBLIC UTILITY BONDS	6.08%
EQUITY RISK PREMIUM	**5.10%**

(a) S&P's Security Price Index Record (1992), The Analysts' Handbook (1967, 1999, Monthly Supplement February 2001)
(b) S&P's Security Price Index Record (1996), Current Statistics (January 1997, March 1998 , December 1999 & January 2001)

AVISTA CORPORATION

OVERALL RATE OF RETURN

Component	Percent of Total Capital	Component Cost	Weighted Cost
Long-term Debt	45.00%	8.77%	3.95%
Short-term Debt	4.00%	8.45%	0.34%
Trust Preferred Securities	7.50%	8.35%	0.63%
Preferred Stock	1.50%	7.39%	0.11%
Common Equity	42.00%	12.75%	5.36%
	100.00%		**10.39%**

APPENDIX A

QUALIFICATIONS OF WILLIAM E. AVERA

WILLIAM E. AVERA

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

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

Summary of Qualifications

Ph.D. in economics and finance; Chartered Financial Analyst (CFA) designation; extensive expert witness testimony before courts, regulatory agencies, alternative dispute resolution panels, and legislative committees throughout the U.S. and Canada. Testimony on economic and financial issues, including antitrust, damages, cost of capital, and business valuation. Lectured in executive education programs around the world; undergraduate and graduate teaching in business and economics; 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, estimation of damages, and industry studies. Provide counseling and educational services, participate in negotiations, 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. Testified in major rate cases and appeared before legislative committees as Chief Economist for regulatory 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, maintained 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.

Former Professional Association Positions: ρ Vice President for Membership, Financial Management Association ρ President, Austin Chapter of Planning Executives Institute ρ Board of Directors, North Carolina Society of Financial Analysts ρ Candidate Curriculum Committee, Association for Investment Management and Research ρ Executive Committee of Southern Finance Association ρ Vice Chair, Subcommittee on Economics and National Association of Regulatory Utility Commissioners (NARUC) ρ Appointed to NARUC's 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 at Albuquerque, Denver, Raleigh and Salt Lake City, 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, 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, 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

Testimony before administrative agencies addressed cost of capital, 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, Arkansas, California, Colorado, Connecticut, Delaware, Hawaii, Idaho, Illinois, Indiana, Kansas, Maryland, Missouri, Nevada, New Mexico, North Carolina, Ohio, Oklahoma, Pennsylvania, South Carolina, Texas, Virginia, Washington, West Virginia, and Wisconcin.

Testimony before federal and state courts, arbitration panels, and alternative dispute resolutions involving damages, valuation, antitrust liability, fiduciary duties, and other economic and financial issues.

Other Professional Activities

ρ Board Member, Georgia System Operations Corporation (electric system operator for Oglethorpe Power Corporation) ρ Co-chair, Synchronous Interconnection Committee, appointed by Governor George Bush and Public Utility Commission of Texas ρ Appointed to Organic Livestock Advisory Committee by Texas Agricultural Commissioner Susan Combs ρ Appointed to research team for Texas Railroad Commission study, *The UP/SP Merger: An Assessment of the Impacts on the State of Texas* ρ Member of team appointed by Hawaii Public Utilities Commission to review affiliate relationships of Hawaiian Electric Industries ρ Consultant to Public Utility Commission of Texas on cogeneration policy and other matters ρConsultant to Public Service Commission of New Mexico on cogeneration policy ρEvaluator of Energy Research Grant Proposals for Texas Higher Education Coordinating.

Community Activities

ρ Board Member, Sustainable Food Center ρ Chairman, Energy Task Force, Greater Austin-San Antonio Corridor Council ρ Chair, Board of Deacons, Finance Committee, and Elder, Central Presbyterian Church of Austin ρ Founding Director, Orange-Chatham County Legal Aid.

Military

ρ Captain, U.S. Naval Reserve (retired after 28 years service) ρ Commanding Officer, Naval Special Warfare (SEAL) Engineering Support Unit ρ Officer-in-charge of SWIFT patrol boat in Vietnam ρ Enlisted service as weather analyst.

Bibliography

Monographs

Ethics and the Investment Professional (video, workbook, and instructor's guide) and *Ethics: Challenge Today* (video), Association for Investment Management and Research (AIMR) (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*, AIMR (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," in *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. Latane 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

"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. Latane in *Proceedings of the Eastern Finance Association* (1973).

Book reviews in *Journal of Finance* and *Financial Review*. Abstracts for *C.F.A. Digest*. Series of articles in *Carolina Financial Times*.

Selected Papers and Presentations

"Ethics," Sponsored by Canadian Council of Financial Analysts 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, Iowa (December 1995). Similar presentations given to National G & T Conference, Irving, Texas (June 1995), Kentucky Association of Electric Cooperatives Annual Meeting, Louisville, Kentucky (Nov. 1994), Virginia, Maryland, and Delaware Association of Electric Cooperatives Annual Meeting, Richmond, Virginia (July 1994), and Carolina Electric Cooperatives Annual Meeting, Raleigh, North Carolina (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, Texas (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).

"Good Ethics is Good Business," Austin Society of Financial Analysts (March 1994). Similar presentations given to San Antonio Society of Financial Analysts (Nov. 1985) and St. Louis Society of Financial Analysts (Feb. 1986).

"Regulatory Developments in Telecommunications," Regional Holding Company Financial and Accounting Conference, San Antonio, Texas (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, Texas (Jun. 1991).

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

"The Role of Utilities in Fostering New Energy Technologies," Emerging Energy Technologies in Texas Conference, Austin, Texas (Mar. 1988).

"The Regulators' Perspective," Bellcore Economic Analysis Conference, San Antonio, Texas (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, Georgia (Sep. 1985).

"Wheeling for Power Sales," Energy Bureau Cogeneration Conference, Houston, Texas (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, Louisiana (Nov. 1982).

"Used and Useful Planning Models," Planning Executive Institute, 27th Corporate Planning Conference, Los Angeles, California (Nov. 1979).

"Staff Input to Commission Rate of Return Decisions," The National Society of Rate of Return Analysts, New York, New York (Oct. 1979).

"Electric Rate Design in Texas," Southwestern Economics Association, Fort Worth, Texas (Mar. 1979).

"Discounted Cash Life: A New Measure of the Time Dimension in Capital Budgeting," with David Cordell, Southern Finance Association, New Orleans, Louisiana (Nov. 1978).

"The Relative Value of Statistics of Ex Post Common Stock Distributions to Explain Variance," with Charles G. Martin, Southern Finance Association, Atlanta, Georgia (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, Canada (Oct. 1976).

"A Growth-Optimal Portfolio Selection Model with Finite Horizon," with Henry A. Latane, American Finance Association, San Francisco, California (Dec. 1974).

"An Optimal Approach to the Finance Decision," with Henry A. Latane, Southern Finance Association, Atlanta, Georgia (Nov. 1974).

"A Pragmatic Approach to the Capital Structure Decision Based on Long-Run Growth," with Henry A. Latane, Financial Management Association, San Diego, California (Oct. 1974).

"Multiperiod Wealth Distributions and Portfolio Theory," Southern Finance Association, Houston, Texas (Nov. 1973).

"Growth Rates, Expected Returns, and Variance in Portfolio Selection and Performance Evaluation," with Henry A. Latane, Econometric Society, Oslo, Norway (Aug. 1973).