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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION	)	CASE NO. AVU-E-04-01
OF AVISTA CORPORATION FOR THE	)	CASE NO. AVU-G-04-01
AUTHORITY TO INCREASE ITS RATES	)	
AND CHARGES FOR ELECTRIC AND	)	
NATURAL GAS SERVICE TO ELECTRIC AND	)	DIRECT TESTIMONY
NATURAL GAS CUSTOMERS IN THE STATE	)	OF
OF IDAHO	)	WILLIAM E. AVERA
	)	

FOR AVISTA CORPORATION

(ELECTRIC AND NATURAL GAS)

I. INTRODUCTION

Q. Please state your name and business address.

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

Q. In what capacity are you employed?

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

A. Qualifications

Q. What are your professional qualifications?

A. I received a B.A. degree with a major in economics from Emory University. After serving in the United States Navy, I entered the doctoral program in economics at the University of North Carolina at Chapel Hill. Upon receiving my Ph.D., 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 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 PUCT, 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 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 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 30 states, including the Idaho Public Utilities Commission (the "Commission" or "IPUC").

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 serve as an outside director of Georgia System Operations Corporation, the system operator for electric cooperatives in Georgia.

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. 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 also have 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 also have 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 in this case?

A. The purpose of my testimony is to present to the Commission my independent evaluation of Avista Corp.'s ("Avista" or "the Company") current cost of common equity for its jurisdictional electric utility operations. I conclude that Avista's current cost of equity significantly exceeds 11.5 percent and endorse strongly the Company's request that this value be used as the rate of return on common equity ("ROE") for purposes of determining the weighted average cost of capital.

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

A. As is common and generally accepted in my field of expertise, I have accessed and used information from a variety of sources. I am familiar with the organization, operations, finances, and operation of Avista from my participation in prior proceedings before the IPUC, the Washington Utilities and Transportation Commission ("WUTC"), and the Oregon Public Utility Commission ("OPUC"). In connection with the present filing, I considered and relied upon corporate disclosures and management discussions, publicly available financial reports and filings, and other published information relating to Avista. I also reviewed information relating generally to current capital market conditions and specifically to current investor perceptions, requirements, and expectations for vertically integrated electric utilities. These sources, coupled with my experience in the fields of finance and utility regulation, have given me a working knowledge of investors' ROE requirements for Avista as it competes to attract capital, and form the basis of my analyses and conclusions.

Q. What is the role of ROE in setting a utility's rates?

A. The rate of return on common equity serves to compensate investors for the use of their capital to finance the plant and equipment necessary to provide utility service. Investors only commit money in anticipation of earning a return on their investment commensurate with that available from other investment alternatives having comparable risks. Consistent with both sound regulatory economics and the standards specified in the *Bluefield*[1] and *Hope*[2] cases, the return on investment allowed a utility 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 your conclusions regarding a fair rate of return for Avista?

A. I first reviewed the operations and finances of Avista and the general conditions in the electric utility industry and the economy. With this as a background, I developed the principles underlying the cost of equity concept and then conducted various

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

generally accepted quantitative analyses to estimate the Company's current cost of equity. These included discounted cash flow ("DCF") analyses and risk premium methods applied to a reference group of electric utilities, as well as reference to earned rates of return expected for utilities and industrial firms. Based on the cost of equity estimates indicated by my analyses, the Company's ROE was evaluated taking into account the specific risks and economic requirements for Avista consistent with restoration and preservation of its financial integrity.

C. Summary of Conclusions

Q. What is your conclusion regarding the reasonableness of the 11.5 percent ROE requested by Avista?

A. Based on my capital market analyses and the economic requirements for electric utility operations, I conclude that a 11.5 percent ROE falls below the current required rate of return for Avista, in light of investors' economic requirements and the Company's specific risks. Results of my quantitative analyses indicated that the cost of common equity for a benchmark group of electric utilities in the western U.S. is presently in the range of 10.4 to 11.9 percent. The investment risks associated uniquely with Avista, however, are significantly greater than those of the utilities in the benchmark group and investors require a higher rate of return to compensate for that risk. Coupled with expectations for higher utility bond yields going forward, at a minimum these greater risks would suggest a rate of return on equity at the uppermost end of the range for the proxy group.

The reasonableness of Avista's requested ROE is further reinforced by investors' continued focus on the uncertainties associated with the electric power industry in which

Avista must operate to meet its energy requirements. Unsettled conditions in western power markets, Avista's reliance on hydrogeneration and purchased power, and regulatory uncertainties all compound the investment risks associated with the Company's jurisdictional utility operations. The cost of fully funding the Company's common equity capital is small relative to the potential benefits that a financially sound utility can have in providing reliable service at reasonable rates; especially when compared against the burden imposed by a financially troubled service provider. Considering the importance of ensuring investor confidence, strengthening Avista's financial standing, and enhancing the Company's ability to attract the capital necessary to expand utility infrastructure, an 11.5 percent rate of return on equity is both necessary and reasonable at this juncture.

II. FUNDAMENTAL ANALYSES

Q. What is the purpose of this section?

A. As a predicate to my economic and capital market analyses, this section briefly describes Avista and reviews its operations and finances. This section also examines the risks and prospects for the electric utility industry as a whole and conditions in the capital markets and the general economy. An understanding of these fundamental factors, which drive the risks and prospects of electric utilities, is essential to developing an informed opinion about current investor expectations and requirements and forms the basis of a fair rate of return on equity.

A. Avista Corp.

Q. Briefly describe Avista.

A. Headquartered in Spokane, Washington, Avista is engaged primarily in the procurement, transmission, and distribution of electric energy and natural gas, as well as other energy-related businesses. 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. In addition to providing electric and natural gas utility service within a 26,000 square mile area of eastern Washington and northern Idaho, Avista's utility segment also provides gas distribution service in 4,000 square miles of northeast and southwest Oregon and in the South Lake Tahoe region of California.

Avista Capital, a wholly owned subsidiary, is the parent company of all non-utility subsidiaries. Through these companies, Avista is engaged in electric and natural gas marketing, trading, and resource management, primarily within the eleven Western states comprising the Western Electricity Coordinating Council, and internet-based specialty billing and information services. As of September 30, 2003, Avista had total assets of approximately $3.4 billion, with consolidated revenues totaling over $980 million for the 2002 fiscal year.

Q. Please describe Avista's electric utility operations.

A. Avista provides retail electric service to approximately 321,000 customers, with principal industries in the area including agriculture, mining, and forestry, as well as health care, electronic and other manufacturing, and tourism. During the 2002 fiscal year, Avista's electric deliveries total 9.8 million megawatt hours ("mWh"). Approximately 42 percent of 2002 retail electric revenues were from residential customers, with 42 percent from commercial and 16 percent from industrial users and street lighting.

Avista's generating facilities include 8 hydroelectric generating stations located in Idaho, Montana, and Washington with a combined capacity of approximately 960 megawatts ("MW"). In addition, Avista holds a 15 percent interest in the coal-fired Colstrip plant (approximately 220 MW) and a 50 percent interest in the 280 MW combined cycle natural-gas fired Coyote Springs 2 facility, which was placed into operation in July 2003. Avista also owns a wood-fired plant with a generating capacity of approximately 50 MW and has four natural gas-fired generating facilities used primarily to meet peak demand. Avista anticipates total capital expenditures for electric utility operations of approximately $230 million for 2004 and 2005.

During 2002, company-owned generation accounted for 55 percent of the electric energy provided by Avista, with the balance being obtained through purchased power and exchanges. The electrical output of Avista's hydroelectric plants, which has a significant impact on total energy costs, is dependent on stream flows, which have fallen significantly below normal levels in recent years. Although Avista estimates that hydroelectric generation is capable of supplying 50 percent of total system requirements under normal conditions, streamflow conditions for 2003 were approximately 85 percent of normal levels. Avista expects that below-normal water conditions will continue into 2004.

Avista's transmission system interconnects the Company with other western electric utilities,permitting the interchange, purchase, and sale of power among all major electric systems in the west. Avista offers firm and non-firm transmission services in the eastern

Washington, northern Idaho, and western Montana areas of the Pacific Northwest. Avista is also participating with nine other western utilities in the possible formation of a Regional Transmission Organization ("RTO"), RTO West. RTO West received limited approval of its Stage 2 proposal from the FERC in September 2002. Fluctuations in the output of the Company's hydroelectric generating facilities due to variable water conditions force Avista to rely more heavily on wholesale power markets to meet its customers' energy needs.

In response to the business and regulatory risks inherent in substantial reliance on wholesale power markets for electricity supply, and recognizing the continuing uncertainty concerning the reliability and volatility of such purchases, Avista has proposed a plan to expand access to additional generating resources and upgrade its electric transmission system. Avista's Integrated Resource Plan has identified the potential need for the Company to finance total expenditures for electric facilities of approximately $725 million over the next ten years.[3] The preferred strategy outlined in Avista's 2003 Integrated Resource Plan, which seeks to reduce exposure to wholesale market volatility, contemplates total expenditures of $2.4 billion over the plan's 20-year horizon. Considering the Company's weakened credit standing, enhancing Avista's financial integrity and flexibility will be instrumental in attracting the capital necessary to fund these projects in an effective manner.

Avista is subject to state retail regulation by the IPUC, the WUTC, the OPUC, and the Public Utilities Commission of the State of California, and at the federal level by 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 agreeing to institute various

[3] Avista Corp., *2003 Integrated Resource Plan* at 48.

protections, mitigation, and enhancement measures in order to address environmental concerns, Avista received new operating licenses covering its two largest hydroelectric facilities – Cabinet Gorge and Noxon Rapids – in 2000. The license covering five hydroelectric plants on the Spokane River expires in August 2007 and the planning and consultation process with stakeholders is 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. How are fluctuations in Avista's operating expenses caused by varying hydro and power market conditions accommodated in its rates?

A. Beginning in 1989, Avista implemented a power cost adjustment mechanism ("PCA"), under which Idaho jurisdictional rates are adjusted periodically to reflect changes in variable power production and supply costs. When hydroelectric generation is reduced and power supply costs rise above those included in base rates, the PCA allows Avista to increase rates to recover a portion of its additional costs. Conversely, if increased hydroelectric generation were to lead to lower power supply costs, rates would be reduced. Although the PCA provides for rates to be adjusted periodically, it applies to 90 percent of the deviation between actual power supply costs and normalized rates.

Q. What credit ratings have been assigned to Avista?

A. Like many other utilities in the region, Avista was adversely affected by volatile and unprecedented energy prices in the western U.S. in 2000 and 2001. Unprecedented increases in wholesale prices, rate structures that did not capture full costs of acquiring fuel and purchased power led to severe liquidity problems, depressed earnings, and debt ratings downgrades. Avista is currently assigned a corporate credit rating of "BB+" by Standard & Poor's Corporation (S&P), with Avista's senior secured debt being rated "BBB-". Similarly, Moody's Investors Service ("Moody's) has assigned an issuer credit rating of "Ba1" Avista, while rating the Company's first mortgage bonds "Baa3". These corporate credit ratings place Avista in the same category as speculative, or "junk," bond companies, with its senior debt ratings occupying the bottom rung on the ladder of the investment grade scale.

B. Electric Power Industry

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

A. The industry is characterized by structural change resulting from market forces, decontrol initiatives and judicial decisions.

Q. Please describe these structural changes.

A. At the federal level, the FERC has been an aggressive proponent of regulatory driven reforms designed to foster greater competition in markets for wholesale power supply. The National Energy Policy Act of 1992, which reformed the Public Utility Holding Company Act of 1935, and to a limited extent, the Federal Power Act, greatly increased prospective competition for the production and sale of power at the wholesale level. In April 1996, FERC adopted Order No. 888, mandating "open access" to the transmission facilities of jurisdictional electric utilities. FERC also has pushed for the regionalization of transmission system control, by establishing frameworks for creation of Regional

Transmission Organizations ("RTOs") in its Order No. 2000.[4] "Open access" has, in the view of most market observers, resulted in more competition and competitors in wholesale power markets, but not without the introduction of substantial risks – particularly for utilities (like Avista) that depend on wholesale power markets for a significant portion of their resource requirements. On July 31, 2002 FERC issued a notice of proposed rulemaking proposing a framework to address alleged discrimination in providing interstate transmission services and in other industry practices.[5] More recently, on April 28, 2003, FERC issued a White Paper refining its vision for a wholesale power market platform, taking into account recent developments in market design and comments filed in response to the earlier SMD NOPR.[6]

Wholesale wheeling provides transmission-dependent electric utilities with additional energy supply options; but it has also introduced new risks to participants in the wholesale power markets. 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. This process of industry transition led to the disaggregation of many formerly integrated electric utilities into three primary components – generation, transmission, and distribution. Presently, however, Avista is, and is expected to remain, a fully integrated public utility.

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[4] *Regional Transmission Organizations*, Order No. 2000 (Dec. 20, 1999), 89 FERC ¶ 61,285.
[55] *Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design*, 67 Fed. Reg. 55,451, FERC Stats. & Regs. ¶ 32,563 (2002) ("SMD NOPR").
[6] FERC White Paper, *Wholesale Power Market Platform*, April 28, 2003, *available at* http://www.ferc.gov/Electric/RTO/Mrkt-Strct-comments/White_paper.pdf.

Q. What impact has the western power crisis had on investors' risk perceptions for firms involved in the electric power industry?

A. During the course of the last several years, investors have dramatically altered their assessment of the relative risks associated with the electric power industry. A well-publicized energy crisis throughout the west has wreaked havoc on the State's customers, utilities, and policymakers. It also has had dramatic repercussions for western wholesale power markets and investors and utilities nationwide. Beyond causing state regulators and legislators to re-evaluate their restructuring initiatives for the retail sector of the electric industry, the financial implications of the western power crisis experience demonstrated the risks facing all segments of the electric power industry.

The massive debts owed by California's retail utilities to banks, power producers and other creditors shattered their financial integrity and the subsequent bankruptcy filing of Pacific Gas and Electric Company ("PG&E") brought the uncertainties associated with today's power markets into sharp focus for the investment community. Enron's, and later Mirant Corporation's, bankruptcies only served to magnify the risks associated with the power sector and increased investors' reluctance to commit capital in the energy industry, as former FERC Commissioner Massey succinctly recognized:

> Sadly, the tsunami of the western energy crisis, coupled with the collapse of Enron, have left a devastating wake within the industry. Investor confidence has been shaken by these events, by a declining national economy, indictments of energy traders, accounting irregularities, downgrades by rating agencies, and continuing investigations by the FERC, CFTC, the SEC, and the Justice

> Department. ...The flight of capital from the industry has been severe since the collapse of Enron.[7]

While the case of California and PG&E represents an extreme example, there is every indication that investors' risk perceptions for electric utilities shifted sharply upward as events in the western U.S. continued to unfold. The resolution is far from over, as even today, the FERC, federal and state courts, and other agencies debate and examine the underlying causes of the volatility, high prices and erratic supply patterns characteristic of western wholesale power markets in 2000 and 2001.

Q. Have these events affected electric utilities' credit standing?

A. Yes. The last several years have witnessed steady erosion in credit quality throughout the electric utility industry, both as a result of revised perceptions of the risks in the industry and the weakened finances of the utilities themselves. For example, during 2002, S&P recorded 182 downgrades in the electric power industry, versus only 15 upgrades, while Moody's downgraded 109 utility issuers and upgraded one; an acceleration of the trend in bond rating changes during the previous two years. Moreover, credit quality has continued to decline. S&P reported an unprecedented 88 ratings downgrades during the first half of 2003 alone,[8] and noted that the utility industry "continued its downward credit slope that was firmly established in early 2000 in this year's third quarter.[9] Similarly, Moody's downgraded 51 utilities between January and June 2003, while upgrading only one firm.[10]

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[7] *Remarks by William L. Massey*, Center for Public Utilities Advisory Council, "The Santa Fe Conference" (March 17, 2003).
[8] Standard & Poor's Corporation, "Credit Quality For U.S. Utilities Continues Negative Trend," *RatingsDirect* (Jul. 24, 2003).
[9] Standard & Poor's Corporation, "Downgrades Continue to Dominate U.S. Rating Actions in Third Quarter," *RatingsDirect* (Oct. 16, 2003).
[10] Moody's Investors Service, *Moody's Credit Perspectives* (Jul. 14, 2003) at 33-34.

Q. What was the impact of these capital and credit market conditions on the ability of electric utilities to raise funds?

A. Combined with a stagnant economy and global uncertainties, the dramatic upward shift in investors' risk perceptions and the weakened financial picture of most industry participants combined to produce a severe liquidity crunch in the electric power industry. S&P cited the debilitating impact of these developments on investors' willingness to provide capital:

> The last 24 months have witnessed extraordinary turmoil for power and energy debt, unprecedented since Samuel Insull's utility empire collapsed during the 1930s. Events ranging from the credit collapse of the California utilities, through the Enron bankruptcy and subsequent market disruptions for U.S. energy merchant companies have destroyed billions of dollars of value for investors. Wall Street has virtually shut down new investment in this sector.[11]

> Increasingly constrained capital market access as a result of investor skepticism over accounting practices and disclosure, more and more federal and state investigations and subpoenas, audits, and failing confidence in future financial performance has created a liquidity crisis.[12]

The challenges faced by electric utilities resulted in reduced financing activity, with many utilities being forced to rely on bank debt. Access to the commercial paper markets, long the low-cost staple of high-grade utility credits for meeting working capital needs, virtually disappeared for certain companies. S&P noted that this falloff in financing activity was partly attributable to "capital market jitters, especially for those firms that are most in need of capital market access."[13] As a result, at the same time that industry uncertainty and market volatility increased the importance of financial flexibility, S&P observed that

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[11] Standard & Poor's Corporation, *2002 Power & Energy Credit Conference: Beyond the Crisis* (Jun. 12, 2002).
[12] Standard & Poor's Corporation, "U.S. Power Industry Experiences Precipitous Credit Decline in 2002; Negative Slope Likely to Continue", *RatingsDirect* (Jan. 15, 2003).
[13] *Id.*

constrained access to capital markets and investor skepticism was contributing to the bleak credit picture.[14]

Q. How has Avista been impacted by the turmoil in the electric power industry?

A. The Company's financial integrity has been severely damaged by the turmoil in the electric power industry. Like others, Avista was swept up in the maelstrom of the western energy crisis. While a full description of the western power crisis and its effects is beyond the scope of this testimony, the chaotic market conditions were felt directly and with full force. Because of Avista's dependence on hydroelectric generation, it has always been exposed to the uncertainties associated with year-to-year fluctuations in water conditions. Nevertheless, the degree of price volatility that participants in the western power markets were forced to assume was unprecedented and variability in short-term market prices bore no resemblance to fluctuations experienced in the past.

Increased wholesale prices and rate structures that did not capture full costs of acquiring fuel and purchased power led to depressed earnings. As of December 31, 2001, for example, Avista had recorded a regulatory asset of $193 million related primarily to power cost deferrals resulting from record low hydroelectric generation and higher purchased power prices.[15] Avista was forced to use cash flows from operations, various bank borrowings, and short- and long-term debt to fund unrecovered energy supply costs. This led to a sharp deterioration in Avista's financial condition, a severe liquidity crunch, and a dramatic increase in credit risk. As a result, commercial banks were reticent to extend financing for ongoing

[14] Standard & Poor's Corporation, "Credit Quality For U.S. Utilities Continues Negative Trend," *RatingsDirect* (Jul. 24, 2003).

operations or new construction, and the Company's power and natural gas suppliers were unwilling to transact business absent special credit terms. To varying degrees, utilities throughout the western U.S. were confronted with the difficult task of maintaining reliable service and financial integrity in a power market characterized by short supply and unprecedented price volatility. Municipal utilities in the Northwest were also forced to approve or propose significant rate increases to recover rising fuel and purchased power costs.[16]

Even for 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. One example of this regulatory lag was noted by The Value Line Investment Survey (Value Line):

> **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.[17]

Because of record low stream flows available to Avista's hydroelectric facilities in 2001 and the resulting dependence on wholesale power markets in the west, the chaotic market conditions were felt directly.

The continuing prospect of further turmoil in western power markets cannot be discounted. Investors recognize that volatile markets, unpredictable stream flows, and

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[15] Avista Corp., Form 10-K Report (2001).

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

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

Avista's reliance on wholesale purchases to meet a portion of its resource needs can create a "perfect storm," exposing the Company to the risk of reduced cash flows and unrecovered power supply costs. In response, Avista's Integrated Resource Plan contemplates an expansion of the electric utility system, including the construction of additional generating resources, to insulate customers and the Company from the risks inherent in substantial reliance on wholesale power markets. Accordingly, strengthening Avista's financial integrity and flexibility will be instrumental in the Company's ability to attract the capital necessary to implement this plan in an effective manner. From the standpoint of the capital markets, the west is risky – and Avista's weakened financial profile and continued exposure to wholesale electric and natural gas markets in meeting shortfalls in hydroelectric generation and other variations in resources and loads compound these uncertainties.

Q. What are the implications of the power outages experienced in the upper Midwest and Northeast during August 2003?

A. These events underscore the continuing risks inherent in the industry and the uncertain state of affairs with respect to the industry's structure. The massive blackout, which stretched from New York to Detroit and from Ohio into Canada, was the largest power outage in U.S. history. This single event has sharpened the focus of industry stakeholders – utilities, consumers, regulators, and investors – on the need to improve the nation's electricity infrastructure, especially in light of the additional stress that deregulated wholesale markets have placed on the network. The importance of rapidly stimulating investment in electric power infrastructure has been almost universally cited as the key to ensuring that further outages are avoided. As FERC Chairman Wood noted:

> If we draw any conclusions from this blackout, it is the urgent need for more investment in the nation's transmission grid to serve broad regional needs.[18]

Indeed, Avista has committed to expand the scope and reliability of its utility system in order to provide customers with the benefits of wholesale competition, while attempting to insulate them from the potential impact of power market anomalies.

Q. Are investors likely to consider the impact of industry uncertainty in assessing their required rate of return for Avista?

A. Absolutely. While electric utility restructuring has not been actively pursued in Idaho, Avista continues to face the prospect of FERC driven changes in the transmission function of their business, as well as more fundamental reforms in how utilities operate to optimize their assets for the benefit of retail ratepayers.[19] As noted earlier, Avista is an active participant in the formation of the proposed RTO West, an independent entity that would operate the transmission grid in seven western states.

Policy evolution in the transmission area has been wide-reaching. Investors' focus on regulatory change in their assessment of risks and prospects was exemplified by S&P:

> The FERC is in the process of changing every aspect of the electric utility landscape, with industry sages anticipating further transmission and wholesale market development guidance, which could affect the segment's credit prospects and quality. ...Significant uncertainty still exists for transmission companies that may operate under an RTO or ISO structure, which will significantly impact the full scope of capital expenditures necessary to ensure

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[18] *Statement of Pat Wood, III, Chairman, Federal Energy Regulatory Commission, On the Power Failure in the U.S. and Canada*, Press Release (Aug. 15, 2003).

[19] See, *e.g.*, *Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design*, 67 Fed. Reg. 55,451, FERC Stats. & Regs. ¶ 32,563 (2002) ("SMD NOPR") and FERC White Paper, *Wholesale Power Market Platform,* April 28, 2003, *available at* http://www.ferc.gov/Electric/RTO/Mrkt-Strct-comments/White_paper.pdf.

> reliability and increase capacity in the future. Uncertainty will exist until operating rules are in place and have stabilized.[20]

Virtually all industry stakeholders have recognized that regulatory uncertainties increase the risks associated with the electric industry. Former FERC Commissioner Massey has noted that regulatory uncertainty is "part of the problem" explaining under-investment in electric utility infrastructure.[21] The Department of Energy ("DOE") identified "reducing regulatory uncertainty" as critical in stimulating increased investment in the power industry and has noted that lack of clarity in the regulatory structure was inhibiting planning and investment.[22] The DOE also recognized the impact that this regulatory uncertainty has on investors' required rates of return for electric utilities:

> Because transmission assets are long lived, regulatory uncertainty increases the risks to investors and, therefore, increases the returns they need to justify transmission system investments.[23]

In remarks before NARUC, a representative of MBIA Insurance Corporation, the world's largest financial guaranty insurance company, noted the increased risks posed by inconsistent regulatory decision-making "have made access to the capital markets very difficult and very expensive."[24] Similarly, while the Consumer Energy Council of America recognized that improvements in electric utility infrastructure are necessary to ensure reliability and support

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[20] Standard & Poor's Corporation, "Electric Transmission at the Starting Gate", *RatingsDirect* (May 10, 2002).
[21] Massey, William L., "Restoring Confidence in Energy Markets", Remarks at the 9th Annual Spring Conference for the New England Energy Industry (May 21, 2002).
[22] U.S. Department of Energy, *National Transmission Grid Study* (May 2002), at 24 and 31.
[23] *Id.* at 31.
[24] *Draft Remarks of Kara M. Silva, Vice President, MBIA Insurance Corporation*, NARUC Joint Committee on Electricity, Gas, and Finance and Technology (Feb. 26, 2003).

the economy, they concluded that regulatory uncertainty "has contributed to a fear of instability for the entire system".[25]

The recent blackout has only served to reinforce the importance of regulatory risks for investors. The Wall Street Journal cited the debilitating impact of an "unsteady regulatory environment" and the "chaotic combination of regulated and deregulated markets" in explaining inhibitions to increased investment in the electric utility system.[26] Similarly, FERC Chairman Wood concluded in his initial comments on the power outages that:

> Clearly, we need regulatory certainty and other incentives for investment.[27]

Nevertheless, S&P recently warned investors that the partial reforms presently characterizing wholesale power markets invites dysfunction and that elevated risks will discourage new capital, "or at least make it more expensive."[28] S&P observed:

> Investors should not expect that such risk will dissipate any time soon. Instead, credit risk could actually intensify if the politically charged debate over reform continues for years, as it might very well do. And even if policy makers succeed in crafting a comprehensive solution to the problems of the nation's energy grid, the regulatory treatment of the costs needed to upgrade the infrastructure remains uncertain.[29]

Because of potential exposure to wholesale markets, the risks of transmission uncertainties and potential market volatility are intensified for utilities that depend heavily on purchased power. Thus, Avista's dependence on purchased power to meet shortfalls in hydroelectric generation magnifies the importance of maintaining the financial flexibility necessary to fund

[25] Consumer Energy Council of America, "Positioning the Consumer for the Future: A Roadmap to an Optimal Electric Power System" (Apr. 2003) at XVII.
[26] Smith, Rebecca, "Overloaded Circuits Blackout Signals Major Weakness in U.S. Power Grid," The Wall Street Journal (Aug. 18, 2003).
[27] *Statement of Pat Wood, III, Chairman, Federal Energy Regulatory Commission, On the Power Failure in the U.S. and Canada*, Press Release (Aug. 15, 2003).
[28] Standard & Poor's Corporation, "Electric Utility Blackouts Put Spotlight on Political and Regulatory Credit Risk", *RatingsDirect* (Aug. 21, 2003).

an adequate and reliable utility system. At the same time, it also exposes the Company and its investors to the ongoing regulatory uncertainties and other risks imposed by federal restructuring of wholesale power markets.

Q. Are these uncertainties the only risks being faced by electric utilities?

A. No. Apart from these factors, the industry continues to face the normal risks inherent in operating electric utility systems, including the potential adverse effects of inflation, interest rate changes, growth, the general economy, and regulatory uncertainty and lag. Electric utilities are confronting increased environmental pressures that leave them exposed to uncertainties regarding emissions and potential contamination. S&P recognized the potential financial challenges posed by such uncertainties:

> Pension obligations, environmental liabilities, and serious legal problems restrict flexibility, apart from the obligations' direct financial implications.[30]

C. Capital Markets and Economy

Q. What has been the pattern of interest rates over the last decade?

A. Average long-term public utility bond rates, the monthly average prime rate, and inflation as measured by the consumer price index since 1990 are plotted in the graph below. After rising to approximately 10 percent in mid-1990, the average yield on long-term public utility bonds generally fell as economic conditions weakened in the aftermath of the 1991 Gulf war, with rates dipping below 7 percent in late 1993. Yields subsequently rose again in 1994, before beginning a general decline, with investors requiring approximately 6.4 percent from average public utility bonds in November 2003:

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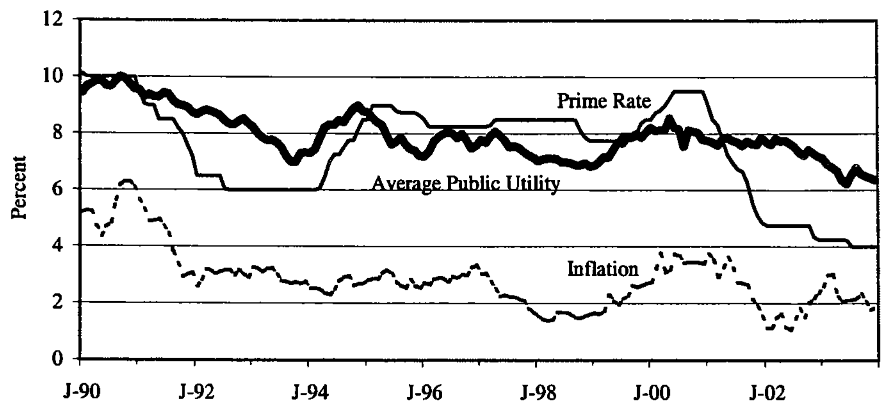
[29] *Id.*



Q. Are investors likely to anticipate any substantial decline in interest rates going forward?

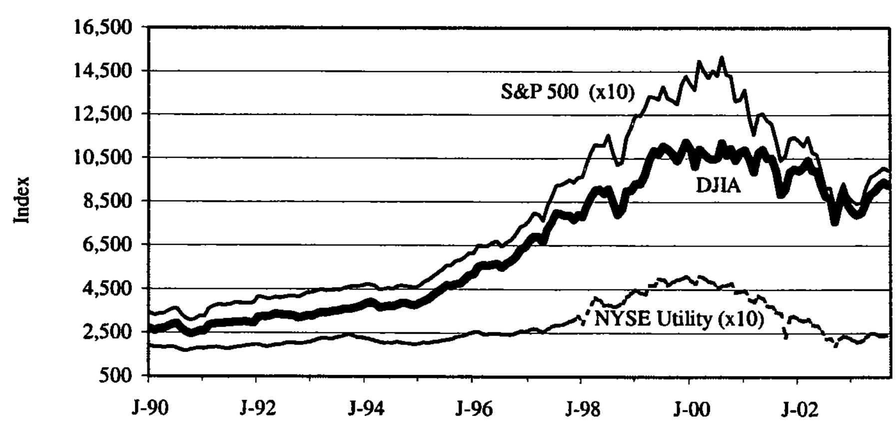
A. No. Since early 2001, a great deal of attention has been focused on the actions of the Federal Reserve as they have moved successively to lower short-term interest rates in response to weakness in the United States economy. But while interest rates are currently at relatively low levels, investors are unlikely to expect any further significant declines going forward. The general expectation is that, as economic growth strengthens, interest rates will begin to rise. For example, the Energy Information Administration ("EIA"), a statistical agency of the DOE, routinely publishes a 25-year forecast for energy markets and the nation's economy. The most recent forecast, released December 16, 2003, anticipates that the double-A public utility bond yield will increase from approximately 6.7 percent in 2004 to 7.49 percent over the next five years, with the average being 7.3 percent over the next 10 years.[31] Similarly, GlobalInsight (formerly DRI/WEFA), a widely referenced forecasting service, calls

[30] Standard & Poor's Corporation, *Corporate Ratings Criteria* at 29, available at www.standardandpoors.com/ratings.
[31] Energy Information Administration, Annual Energy Outlook 2004, Table 20 (Dec. 16, 2003).

for double-A public utility bond yields to average 7.35 percent over the next ten years, with yields ranging between 6.70 and 8.02 percent.[32]

Q. How has the market for common equity capital performed?

A. Between 1990 and early 2000 stock prices pushed steadily higher as the longest bull market in United States history continued unabated. While the S&P 500 had increased over four times in value by August 2000, mounting concerns regarding prospects for future growth, particularly for firms in the high technology and telecommunications sectors, pushed equity prices lower, in some cases precipitously. While common stock prices have recovered strongly from recent lows, the market remains volatile, with share values 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, and the New York Stock Exchange Utility Index since 1990 (the latter two indices were scaled for comparability):



[32] GlobalInsight, "The U.S. Economy, The 25-Year Focus", Table 33 (Summer 2003).

Q. What is the outlook for the United States economy?

A. During the decade through the first quarter of 2001, the United States economy 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 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 were exemplified by the Federal Reserve's sequential lowering of interest rates. The economic picture has brightened more recently, with gross domestic product surging 8.2 percent in the third quarter of 2003. Manufacturing activity has rebounded and construction spending has increased. Nevertheless, businesses have been reluctant to expand hiring and uncertainties over the durability of the economy recovery continue to be magnified by the aftermath of war in Iraq, which undermines consumer confidence and contributes to global economic uncertainty. These factors cause the outlook to remain tenuous, with persistent stock and bond price volatility providing tangible evidence of the uncertainties faced by the United States economy.

Q. How do these economic uncertainties affect electric utilities?

A. Uncertainties over the extent and durability of the economic recovery have combined to heighten the risks faced by electric utilities. Stagnant economic growth would undoubtedly mean flat electric sales, while the potential for higher inflation and interest rates that would likely accompany an economic rebound would place additional pressure on the adequacy of existing service rates. While the economy may ultimately return to a path of steady growth and the volatility in the capital and energy markets may abate, the underlying weaknesses now present cause considerable uncertainties to persist, which increase the risks faced by the electric utility industry.

III. 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 a benchmark group 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, DCF and risk premium analyses are conducted to estimate the cost of equity for a reference group of electric utilities.

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 is the cost of inducing and retaining investment in the utility's physical plant and assets. This investment is necessary to finance the asset base needed to provide utility service. Competition for investor funds is intense and investors are free to invest their funds wherever they choose. 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. Moreover, the return on common equity is integral in achieving the sound regulatory 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. What fundamental economic principle underlies this cost of equity concept?

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.

The cost of equity concept is predicated on the notion that investors are risk averse and willingly bear additional risk only if compensated for doing so. 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 – including debt and equity – compete with each other for scarce 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:

$$K_i = R_f + RP_i$$

where: R_f = Risk-free rate of return; and
RP_i = Risk premium required to hold 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. Does the risk-return tradeoff principle actually operate in the capital markets?

A. Yes. The risk-return tradeoff is readily observable 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, which are considered free of default risk, and bonds of various rating categories demonstrate that the risk-return tradeoff does, in fact, exist in the capital markets.

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 is complicated by two factors, however. 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. Nevertheless, it is a fundamental tenet 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. This has been supported and demonstrated by considerable empirical research in the field of finance and is confirmed by reference to historical earned rates of return, with realized rates of return on common stocks exceeding those on government and corporate bonds over the long-term.[33]

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. Debt, preferred stock, and common equity vary considerably in risk because they have different characteristics and priorities.

When investors loan money to a utility in the form of long-term debt, they enter into a contract under which the utility agrees to pay a specified amount of interest and to repay the principal of the loan in full at the maturity date. The bondholders have a senior claim on a utility's available cash flow for these payments, and if the utility fails to make them, bondholders may force it into bankruptcy and liquidation for settlement of unpaid claims. Following first mortgage bonds are other debt instruments also holding contractual claims on the utility's cash flow, such as debentures and notes. Similarly, when a utility sells investors preferred stock, the utility promises to pay specified dividends and, typically, to retire the preferred stock on a predetermined schedule. The rights of preferred stockholders 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 investors in line are common shareholders. They receive only the cash flow, if any, that remains after all other claimants – employees, suppliers, governments, lenders, have been paid. As a result, the rate of return that investors require from a utility's common

[33] See *e.g.*, IbbotsonAssociates, *2003 Yearbook.*

stock, the most junior and riskiest of its securities, is considerably higher than the yield on the utility's 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 prospective 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' current 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. Have you relied on a single method to estimate the cost of equity for Avista?

A. No. In my opinion, no single method or model should be relied upon to determine a utility's cost of equity because 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.[34]

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

Therefore, in addition to the DCF model, I applied the risk premium method based on data for electric utilities and using forward-looking estimates of required rates of return. In addition, I also evaluated my results using a comparable earnings approach based on investors' current expectations in the capital markets. In my opinion, comparing estimates produced by one method with those produced by other approaches 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 in 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 assumes 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:

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

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 (ke) 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 always fully met?

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. Nevertheless, where earnings are derived from stable activities, and earnings, dividends, and book value track fairly closely, the constant growth form of the DCF model offers a reasonable working approximation of stock valuation that provides useful insight as to investors' required rate of return.

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

A. Avista's recent financial challenges and weakened credit standing hinder the application of the DCF model directly to the Company. As an alternative, the cost of equity is often estimated by applying the DCF model to publicly traded firms engaged in the same business activity. In order to reflect the risks and prospects associated with Avista's jurisdictional utility operations, my DCF analyses focused on a reference group of other electric utilities composed of those companies included by Value Line in their Electric Utilities (West) Industry group. Excluded from my analyses were five firms that do not pay common dividends or recently cut their payout and two that were rated below investment grade by S&P (including Avista). Given that these eight utilities are all engaged in electric utility operations in the western region of the U.S., investors are likely to regard this group as facing similar market conditions and having comparable risks and prospects. There are important factors distinguishing western utilities from those located in other regions, including customer density and the complexities associated with greater reliance on hydroelectric generation. Indeed, as noted earlier, the ongoing uncertainties associated with hydroelectric generation and western power markets are important considerations in evaluating investors' required rate of return for Avista.

Q. What other considerations support the use of a proxy group in estimating the cost of equity for Avista?

A. Apart from recognizing the inherent risks and prospects for an electric utility operating in the west, reference to a proxy group of electric utilities is essential to insulate against vagaries that can result when the stochastic process involved in estimating the cost of equity is applied to a single company. The cost of equity is inherently unobservable and can only be inferred indirectly by reference to available capital market data. To the extent that the data used to apply the DCF model does not capture the expectations that investors have incorporated into current stock prices, the resulting cost of equity estimates will be biased. For example, the potential for mergers or acquisitions or the announced sale of a major business segment would undoubtedly influence the price investors would be willing to pay for a utility's common stock. But because such factors are not typically reflected in the growth rates used to apply the DCF model, cost of equity estimates for any single company may fail to reflect investors' required rate of return. Indeed, using even a limited group of companies increases the potential for error, as the FERC noted in its July 3, 2003 *Order on Initial Decision* in Docket No. RP00-107-000:

> Both Staff and Williston agreed that a proxy group of only three companies presented problems because "a single company will have a magnified influence on the group results." It was with those changing market dynamics in mind that witnesses of both Staff and Williston proposed to expand the group of proxy companies to determine a zone of reasonableness.[35]

A proxy group composed of western electric utilities is consistent not only with the shared circumstances of electric power markets in the west, but also with the need to ensure against the potential that a single cost of equity estimate may not reflect investors' required rate of return.

Regulatory and economic standards require that the allowed rate of return should reflect what investors expect for a utility of comparable risk. As will be described

[35] *Williston Basin Interstate Pipeline Co.*, 104 FERC ¶ 61,036, at 14-15 (Jul. 3, 2003).

subsequently, Avista's investment risks exceed those of the utilities in the benchmark group. Accordingly, because investors require a higher rate of return to bear increased risk, this implies that the Company's cost of equity exceeds that of the proxy group of western electric utilities.

Q. Why did you excluded from your benchmark group firms that do not pay common dividends, cut their dividend payout, or have below investment grade bond ratings?

A. As discussed earlier, under the DCF approach, observable stock prices are a function of the cash flows that investors' expected to receive, discounted at their required rate of return. Because dividend payments are a key parameter required to apply the DCF method, this hinders application of the DCF model to firms that do not pay common dividends or have recently cut their payout. Meanwhile, the financial stress and lack of stability that accompanies below investment grade bond ratings greatly complicates any determination of investors' long-term expectations that form the basis for DCF applications to estimate the cost of equity. It is not practicable to apply the DCF model directly to Avista.

Q. What form of the DCF model did you use?

A. I applied the constant growth DCF model to estimate the cost of equity for Avista, which is the form of the model most commonly relied on to establish the cost of equity for traditional regulated utilities and the method most often referenced by regulators.

Other forms of the general, or non-constant DCF model, such as "two-stage" or "multi-stage" analyses can be used to estimate the cost of equity; however, such approaches increase the number of inputs that must be estimated and add to the computational difficulties. While such methods might be warranted when investors expect a discontinuity in the operations of a particular firm or industry, they generally require several very specific assumptions regarding investors' expected cash flows that must occur at given points in the future. This makes the results of non-constant growth DCF applications sensitive to changes in assumptions and, therefore, subject to greater controversy in a rate case setting.

Moreover, to the extent that each of these time-specific suppositions about future cash flows do not reflect what real-world investors actually anticipate, the resulting cost of equity estimate will be biased. Indeed, the benchmark for growth in a DCF model is what investors expect when they purchase stock. Unless we replicate investors' thinking, we cannot uncover their required returns and thus the market cost of equity. In practice, applying a non-constant DCF model would lead to error if it ignores the requirements of real-world investors.

Q. Are there circumstances where a multi-stage DCF model might be preferable to the constant growth form?

A. Yes. The greater complexity of the non-constant growth DCF model is sometimes warranted when it is evident that investors anticipate a well-defined shift in growth rates over the horizon of their expectations. For example, in response to structural reforms introduced in the early 1990s, it was widely anticipated that certain segments of the electric power industry would transition from fully regulated to competitive businesses. Because of the difficulty associated with capturing these expectations in the single growth measure of the constant growth DCF model, many witnesses, including myself, chose to apply a multi-stage approach. A number of regulatory commissions also departed from the simplicity of the constant growth DCF model that they had traditionally favored in order to recognize the transition to competition that was anticipated by investors.

But acceptance of the multi-stage DCF model was predicated on very specific assumptions tailored to investors' actual expectations at the time. As discussed earlier, however, investors are no longer anticipating that such a transition will take place going forward. Broad-reaching structural changes once anticipated by investors at the state and federal levels have been largely effectuated to the extent investors expect them to occur. In the minds of investors, any new initiatives focused on deregulation of the electric utility industry at the retail level have been indefinitely postponed or abandoned altogether. This is certainly true in Idaho, where retail deregulation is not being actively pursued.

While the complexity of non-constant DCF models may impart an aura of accuracy, there is no evidence that investors' current view of electric utilities anticipates a series of discrete, clearly defined stages. As a result, despite the considerable uncertainties now confronting the electric utility industry, there is no discernable transition that would support use of the multi-stage DCF approach.

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 sometimes 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 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 reference group 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 reference group of electric utilities are presented on Schedule WEA-1. As shown there, dividend yields for the eight firms in the electric utility proxy group ranged from 2.9 percent to 5.4 percent, with the average being 4.2 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 ongoing turmoil in the power industry. Thus, apart from the fact that investors do not currently expect a clearly-defined shift in growth rates for electric utilities, these unsettled conditions make the specific forecasts required to implement the non-constant growth DCF model even more tenuous.

Q. Are 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 business risks in the industry have become more accentuated. Thus, while dividends have remained largely stagnant as utilities conserve financial resources to provide a hedge against heightened uncertainties, earnings may be expected to grow at a much swifter pace. Investors' focus has increasingly shifted from dividends to earnings as a measure of long-term growth, as payout ratios for firms in the electric utility industry have been trending downward from approximately 80 percent historically to on the order of 60 percent.[36] As a result, 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.

[36] See, *e.g.*, The Value Line Investment Survey (Sep. 15, 1995 at 161, Sep. 5, 2003 at 154).

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

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 the Association for Investment Management and Research:

> [E]arnings, 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 International, Inc. ("IBES"), focus on growth in earnings indicates that the investment community regards this as a superior indicator of future long-term growth. Indeed, Financial Analysts Journal reported the results of a survey conducted to determine what analytical techniques investment analysts actually use.[39] Respondents were asked to rank the relative importance of earnings, dividends, cash flow, and book value in analyzing securities. Of the 297 analysts that responded, only 3 ranked dividends first while 276 ranked it last. The article concluded:

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[37] Association for Investment Management and Research, "Finding Reality in Reported Earnings: An Overview", p. 1 (Dec. 4, 1996).
[38] The Value Line Investment Survey, *Subscriber's Guide*, p. 53.

Earnings and cash flow are considered far more important than book value and dividends.[40]

Q. What are security analysts currently projecting in the way of earnings growth for the firms in the electric utility proxy group?

A. The consensus earnings growth projections for each of the firms in the reference group of electric utilities reported by IBES and published in S&P's Earnings Guide are shown on Schedule WEA-2. Also presented are the earnings growth projections reported by Value Line, First Call Corporation ("First Call"), and Multex Investor ("Multex"), which is a service of Reuters. As shown there, with the exception of Value Line's estimates, these security analysts' projections suggested growth the order of 5.1 to 5.4 percent for the reference group of electric utilities:

Electric Utility Proxy Group

Service	Growth Rate
IBES	5.1%
Value Line	2.4%
First Call	5.2%
Multex	5.4%

Q. What other earnings growth rates might be relevant in assessing investors' current expectations for electric utilities?

A. Short-term projected growth rates may be colored by current uncertainties regarding the near-term direction of the economy in general and the spate of challenges faced in the electric power industry specifically. Consider the example of Value Line, which recently noted that the electric utility industry "is still in a state of flux"[41] and that:

[39] Block, Stanley B., "A Study of Financial Analysts: Practice and Theory", *Financial Analysts Journal* (July/August 1999).
[40] *Id.* at 88.
[41] The Value Line Investment Survey (July 4, 2003) at 695.

> ...this industry still faces problems. The after-effects of the turbulence in the power markets still exist, some companies are stressed financially, and even for traditional utilities, regulatory risk is often a potential problem.[42]

Value Line has also reduced its Timeliness ranking, a relative measure of year-ahead stock price performance for the 98 industries it covers, for the electric utility industry from 70 to 87.[43] While this cautious outlook may explain the fact that Value Line's near-term growth estimates are out of line with other analysts' projections, it is not necessarily indicative of investors' long-term expectations for the industry.

Given the unsettled conditions in the economy and electric utility industry over the near-term, historical growth in earnings might also provide a meaningful guide to investors' future expectations. Accordingly, earnings growth rates for the past 10- and 5-year periods reported by Value Line for the firms in the electric utility group are also presented on Schedule WEA-2. As shown there, 10-year historical earnings growth rates for the group of eight electric utilities averaged 7.3 percent, or 8.1 percent over the most recent 5 year period.

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

[42] The Value Line Investment Survey (Aug. 15, 2003) at 1776.

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 reference group of electric utilities?

A. The sustainable, "b x r" growth rates for each firm in the reference group is shown on Schedule WEA-3. For each firm, 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 group of electric utilities of 4.6 percent.

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

A. I concluded that investors currently expect growth on the order of 5.0 to 7.0 percent for the average firm in the electric utility proxy group. This determination was based on the growth projections discussed above, but giving little weight to Value Line's projections, which deviated significantly from the more broadly-based consensus growth rate projections reported by IBES and Multex, as well as past experience.

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[43] The Value Line Investment Survey (Jan. 2, 2004) at 695.

Q. What cost of equity was implied for the reference group of electric utilities using the DCF model?

A. Combining the 4.2 percent average dividend yield with the 6.0 percent midpoint of my representative growth rate range implied a DCF cost of equity for this group of electric utilities of 10.2 percent.

C. Risk Premium Analyses

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

A. As I have mentioned previously, because the cost of equity is inherently unobservable, no single method should be considered a solely reliable guide to investors' required rate of return. Accordingly, I also evaluated the cost of equity for Avista using risk premium methods. My applications of the risk premium method provide alternative approaches to measure equity risk premiums that focused specifically on data for electric utilities and forward-looking estimates of investors' required rates of return.

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 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 for electric utilities, (2) realized rates of return on electric utility common stocks; and (3) forward-looking applications of the Capital Asset Pricing Model ("CAPM"). 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. The CAPM approach measures the market-expected return for a security as the sum of a risk-free rate and a risk premium based on the portion of a security's risk that cannot be eliminated by holding a well-diversified portfolio. Under the CAPM, risk is represented by the beta coefficient (∃), which measures the volatility of a security's price relative to the market at a whole. Even before the widely cited study by

Eugene F. Fama and Kenneth R. French,[44] considerable controversy surrounded the validity of beta as a relevant measure of a utility's investment risk. Nevertheless, the CAPM is routinely referenced in the financial literature and in regulatory proceedings.

While these methods are premised on different assumptions, each having their own strengths and weaknesses, they are widely accepted approaches that have been routinely referenced in estimating the cost of equity for regulated utilities.

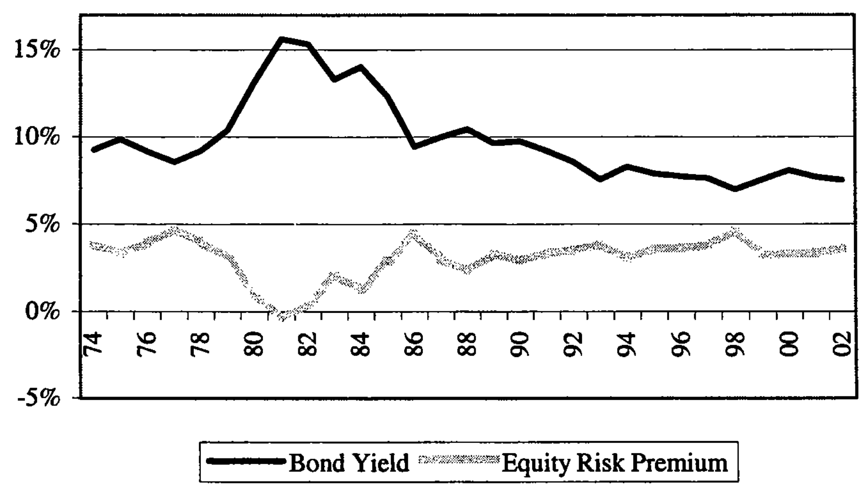
Q. How did you implement the risk premium approach using surveys of allowed rates of return?

A. While the purest form of the survey approach would involve querying investors directly, 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 Regulatory Research Associates ("RRA") and published in its Regulatory Focus report. In Schedule WEA-4, 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 2002. Over this 29-year period, these equity risk premiums for electric utilities averaged 3.08 percent, and the yield on public utility bonds averaged 9.81 percent.

[44] Fama, Eugene F. and French, Kenneth R., "The Cross-Section of Expected Stock Returns", *The Journal of Finance* (June 1992).

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

A. Yes. 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 (solid line) and equity risk premiums (shaded line) shown on Schedule WEA-4:



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.

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 output between the interest rates and equity risk premiums displayed at the bottom of Schedule WEA-4, the equity risk premium for electric utilities increased approximately 43 basis points for each percentage point drop in the yield on average public utility bonds. As illustrated there, with the yield on public utility bonds in December 2003 being 345 basis points lower than the average for the study period, this implied a current equity risk premium of 4.58 percent for electric utilities. Adding this equity risk premium to the December 2003 yield on triple-B public utility bonds of 6.61 percent produces a current cost of equity for the utilities in the benchmark group of approximately 11.2 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.[45] By focusing on data for electric utilities specifically, my realized rate of return approach avoided the need to make assumptions regarding relative risk (*e.g.*, beta) that are often embodied in applications of this method.

Stock price and dividend data for the electric utilities included in the S&P 500 Composite Index ("S&P 500") are available since 1946. Schedule WEA-5 presents annual realized rates of return for these electric utilities in each year between 1946 and 2002. As shown there, over this 57-year period realized rates of return for these utilities have exceeded those on single-A public utility bonds by an average of 4.01 percent. 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 4.01-percent equity risk premium to the November 2003 yield of 6.61 percent on triple-B public utility bonds produces a current cost of equity for the electric utility proxy group of approximately 10.6 percent.

Q. Please describe your application of the CAPM.

A. The CAPM is a theory of market equilibrium that measures risk using the beta coefficient. Under the CAPM, investors are assumed to be fully diversified, so the relevant risk of an individual asset (*e.g.*, common stock) is its volatility relative to the market as a whole. Beta reflects the tendency of a stocks price to follow changes in the market. A stock that tends to respond less to market movements has a beta less than 1.00, while stocks that tend to move more than the market have betas greater than 1.00. The CAPM is mathematically expressed as:

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[45] Indeed, average realized rates of return for historical periods are widely reported to investors in the financial press and by investment advisory services as a guide to future performance.

$$R_j = R_f + \exists_j(R_m - R_f)$$

Where: R_j = required rate of return for stock *j*;
R_f = risk-free rate;
R_m = expected return on the market portfolio; and,
$\exists_j$ = beta, or systematic risk, for stock j.

Schedule WEA-6 presents an application of the CAPM to the eight companies in the electric utility proxy group based on a forward-looking estimate for investors' required rates of return from common stocks. Rather than using historical data, the expected market rate of return was estimated by conducting a DCF analysis on the firms in the S&P 500. The dividend yield was obtained from S&P, with the growth rate equal to the average of the composite earnings growth projections published by IBES for each firm. As shown there, subtracting a 5.2 percent risk-free rate based on the December 2003 average yield on long-term government bonds from the 13.7 percent forward-looking rate of return produced a market equity risk premium of 8.5 percent. Multiplying this risk premium by the average Value Line beta of 0.77 for the firms in the electric utility group, and then adding the resulting risk premium to the long-term Treasury bond yield, resulted in a current cost of equity of approximately 11.7 percent.

D. Proxy Group Cost of Equity

Q. What did you conclude with respect to the cost of equity for the benchmark group of electric utilities?

A. The cost of equity estimates implied by my quantitative analyses are summarized in the table below:

Method	**Cost of Equity Estimate**
DCF	10.2%
Risk Premium	
Authorized Returns	11.2%
Realized Rates of Return	10.6%
CAPM	11.7%

Consistent with the results of my quantitative analyses, I concluded that the cost of equity for the proxy group is presently in the 10.2 to 11.7 percent range.

Q. What other considerations are relevant in setting the return on equity for a utility?

A. The common equity used to finance the investment in utility assets is provided from either 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 common 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.

Q. Is there an established mechanism for a utility to recognize equity issuance costs?

A. No. While debt flotation costs are recorded on the books of the utility, amortized over the life of the issue, and thus increase the effective cost of debt capital, there is no similar accounting treatment to ensure that equity flotation costs are recorded and ultimately recognized. Alternatively, no rate of return is authorized on flotation costs necessarily incurred to obtain a portion of the equity capital used to finance plant. In other words, equity flotation costs are not included in a utility's rate base because neither that portion of the gross proceeds from the sale of common stock used to pay flotation costs is available to invest in plant and equipment, nor are flotation costs capitalized as an intangible asset. 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. Because there is no accounting convention to accumulate the flotation costs associated with equity issues, they must be accounted for indirectly, with an upward adjustment to the cost of equity being the most logical mechanism.

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

A. There are any number of ways in which a flotation cost adjustment can be calculated, and the adjustment can range from just a few basis points to more than a full percent. One of the most common methods used to account for flotation costs in regulatory proceedings is to apply an average flotation-cost percentage to a utility's dividend yield. Based on a review of the finance literature, Roger A. Morin concluded:

> The flotation cost allowance requires an estimated adjustment to the return on equity of approximately 5% to 10%, depending on the size and risk of the issue.[46]

Applying these expense percentages to a representative dividend yield for an electric utility of 4.2 percent implies a flotation cost adjustment on the order of 20 to 40 basis points.

[46] Roger A. Morin, *Regulatory Finance: Utilities' Cost of Capital*, 1994, at 166.

Q. What then is your conclusion regarding a fair rate of return on equity for the companies in your benchmark group?

A. After incorporating a minimum adjustment for flotation costs of 20 basis points to my "bare bones" cost of equity range, I concluded that a fair rate of return on equity for the proxy group of electric utilities is currently in the 10.4 to 11.9 percent range.

IV. RETURN ON EQUITY FOR AVISTA CORP.

Q. What is the purpose of this section?

A. This section addresses the economic requirements for Avista's return on equity. It examines other factors properly considered in determining a fair rate of return, such as market perceptions of Avista's relative investment risks and comparable earnings for utilities and industrial firms. This section also discusses the relationship between ROE and preservation of a utility's financial integrity and the ability to attract capital.

A. Capital structure

Q. Is an evaluation of the capital structure maintained by a utility relevant in assessing its return on equity?

A. Yes. Other things equal, a higher debt ratio, or lower common equity ratio, translates into increased financial risk for all investors. A greater amount of debt means more investors have a senior claim on available cash flow, thereby reducing the certainty that each will receive his contractual payments. This increases the risks to which lenders are exposed, and they require correspondingly higher rates of interest. From common shareholders' standpoint, a higher debt ratio means 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.

Q. What common equity ratio is implicit in Avista's requested capital structure?

A. Avista's capital structure is presented in the testimony of Mr. Malquist. As summarized in his testimony, the common equity ratio used to compute Avista's overall rate of return was 44.3 percent in this filing.

Q. How does Avista's common equity ratio compare with those maintained by the reference group of utilities?

A. As shown on Schedule WEA-7, for the eight firms in the Electric Utility (West) group, common equity ratios at September 30, 2003 ranged from 34.6 percent to 58.1 percent and averaged 44.7 percent.[47]

Q. What implication does the increasing risk of the electric power industry have for the capital structures maintained by utilities?

A. The challenges imposed by the evolving structural changes in the industry imply that utilities will be required to incorporate relatively greater amounts of equity in their capital structures. Moody's noted early on that utilities must adopt a more conservative financial posture if credit ratings are to be maintained:

> "The key issue," says the analysts in a recent special comment, "is that the competitive industries have much lower operating and financial leverage and

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[47] Puget Energy subsequently announced a sale of common stock, with the net proceeds expected to total approximately $100 million. Other things equal, considering this stock sale would result in an average equity ratio for the benchmark group of 45 percent, with only one company (Pinnacle West Capital) having a common equity ratio below 40 percent.

> 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.[48]

As shown on Schedule WEA-7, Value Line expects that the average common equity ratio for the proxy group of eight western electric utilities will increase to 52.7 percent over the next three to five years.

The continued decline in credit quality in the electric industry is indicative of the need for utilities to strengthen financial profiles to deal with an increasingly uncertain and competitive market. S&P cited the inadequacy of current balance sheets in the electric industry as one of the key factors explaining this deterioration:

> The downward slope in the power industry's credit picture can be traced to higher debt leverage and overall deterioration in financial profiles, constrained access to capital markets as a result of investor skepticism over accounting practices and disclosure, liquidity problems, financial insolvency, and investments outside the traditional regulated utility business, principally merchant generation facilities and related energy marketing and trading activities.[49]

A more conservative financial profile is consistent with the increasing uncertainties associated with restructuring and the imperative of maintaining continuous access to capital, even during times of adverse capital market conditions.

Q. How does Avista's capital structure compare with other widely cited financial benchmarks for electric utilities?

A. The financial ratio guidelines published by S&P specify a range for a utility's total debt ratio that corresponds to each specific bond rating. Widely cited in the investment

[48] Moody's Investors Service, *Credit Risk Commentary*, p. 3 (July 29, 1996).
[49] Standard & Poor's Corporation, *Credit Quality For U.S. Utilities Continues Negative Trend*, RatingsDirect, Jul. 24, 2003.

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., triple-B) 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. S&P has assigned Avista a *business profile* ranking of "5".[50]

S&P's current capital structure guideline ratios are attached as Schedule WEA-8.[51] These capitalization benchmarks are presented in the form of total debt ratios, with the remainder of capital structure being composed of equity. Consistent with S&P's current ratings criteria and Avista's S&P *business profile* ranking of "5", as shown on Schedule WEA-8, a utility would be required to maintain a ratio of total debt to total capital on the order of 51.0 percent to qualify for a triple-B bond rating. This benchmark equates to a total equity ratio of 49.0 percent to qualify for a rating at the very bottom of the investment grade scale.

Q. How do the rating agencies view preferred trust securities and preferred stock in their assessment of a company's capital structure?

A. The rating agencies recognize the specific structure of preferred trust securities and preferred stock in evaluating financial leverage. Depending on the degree of permanence and other attributes, preferred securities may be considered more "debt-like" and only a

[50] Standard & Poor's Corporation, *Utilities & Perspectives* (Dec. 22, 2003)
[51] Standard & Poor's, *Corporate Ratings Criteria 2004* (Nov. 13, 2003) at 54, available at www.standaredandpoors.com/ratings.

portion of the outstanding balance will receive equity treatment in assessing the company's capitalization. As a result, a portion of the preferred trust securities and preferred stock that Avista has in its capital structure may be treated more as debt than equity in evaluating the Company's financial risk.

Q. What conclusions can you draw from Avista's proposed capital structure as to how the rating agencies would view it?

A. While the rating agencies consider a plethora of factors besides a company's capital structure when determining a credit rating, financial leverage is an important component of the rating analysis. Considering that only a portion of Avista's preferred trust securities and preferred stock is likely to receive equity treatment, the total equity ratio implied by Avista's proposed capital structure would barely meet the targets that S&P expects for a "BBB"-rated utility.

Q. What other indications confirm the reasonableness of Avista's requested capital structure?

A. In the wake of recent turmoil in the electric power industry, bond rating agencies and investors are continuing to scrutinize debt levels. For those firms with higher leverage, this intense focus can lead not only to ratings downgrades, but to reduced access to capital and increased borrowing costs. The Wall Street Journal reported that even firms with stock prices at recent lows may be forced to issue new common equity in adverse markets and quoted a credit analyst with Fitch, Inc.:

> "[B]anks are fearful to put more money into the sector" and it is making credit analysts nervous as well. The smart companies, he says, are the ones that voluntarily "get their balance sheets in line" and the "let the market know

> they're in charge of their destiny...since the market clearly has the heebie-jeebies."[52]

The article went on to note the crucial role that financial flexibility plays in ensuring that the utility has the wherewithal to meet the needs of customers, especially during times of stress:

> All the belt tightening spells bad news for the continued development of the nation's energy infrastructure. Companies that can borrow more money and stretch their dollars, quite simply, can build more plants and equipment. Companies that are increasingly dependent on equity financing – particularly in a bear market – can do less.[53]

Q. What did you conclude with respect to Avista's requested capitalization?

A. Avista's proposed capital structure is in-line with industry standards, although its requested equity ratio of 44.3 percent falls slightly below the 44.7-percent average for the electric utility benchmark group. Similarly, the total equity ratio implied by Avista's requested capital structure equity ratio would barely meet S&P's published benchmarks for the lowest investment grade credit rating. The reasonableness of Avista's requested capital structure is reinforced by the ongoing uncertainties associated with the electric power industry, the need to support Avista's efforts to strengthen its credit standing, and the imperative of maintaining continuous access to capital, even during times of adverse industry and market conditions.

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[52] Smith, Rebecca, "Rating Agencies Crack Down on Utilities", The Wall Street Journal, p. C1 (December 19, 2001).

[53] *Id.*

B. Relative Risks

Q. How does Avista's credit rating compare to those of the reference groups?

A. The average corporate credit rating for the Electric Utility (West) group used to estimate the cost of equity is "BBB". As noted earlier, Avista's corporate rating is currently "BB+".

Q. What does Avista's credit rating imply with respect to the rate of return required by investors?

A. The cost of equity estimates developed earlier for the benchmark group of electric utilities are predicated on the investment risks associated with the utilities in the proxy group, which have corporate credit ratings of triple-B or higher. Meanwhile, Avista's below investment grade rating is indicative of an entirely different risk class. Because investors require a higher rate of return to compensate them for bearing more risk, the greater investment risk implied by Avista's credit ratings suggests that the cost of equity is correspondingly higher than for the proxy groups.

Q. What is the significance of "investment grade" versus "below investment grade"?

A. The term "investment grade" refers to a security having sufficient quality, or relatively low risk, to be suitable for certain investment purposes. In discussing this distinction, S&P noted that:

> The term "investment grade" was originally used by various regulatory bodies to connote obligations eligible for investment by institutions such as banks, insurance companies, and savings and loan associations. Over time, this term gained widespread usage throughout the investment community. Issues rated in the four highest categories, 'AAA', 'AA', 'A', 'BBB', are recognized as

> being investment grade. Debt rated 'BB' or below generally is referred to as speculative grade. The term "junk bond" is merely a more irreverent expression for this category of more risky debt.[54]

There is a precipitous increase in risk associated with moving from investment grade to below investment grade securities. S&P documented this in its description of the risks associated with triple-B rated bonds and below investment grade instruments:

> 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 to meet its financial commitment on the obligation. Obligations rated 'BB', 'B', 'CCC', and 'C' are regarded as having significant speculative characteristics. 'BB' indicates the least 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.[55]

A study conducted by Moody's indicated that default rates on double-B rated bonds exceeded those for triple-B rated debt by a factor of 5.82 times over the period 1970 through 2002.[56] Thus, bond ratings 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 the firm is regarded as a speculative investment.

Q. Is there any direct capital market evidence regarding the amount of the premium investors require from a firm that is rated double-B, such as Avista?

A. Although rates of return on equity for below investment grade firms cannot be directly observed, the observed yields on long-term bonds provide direct evidence of the additional return that investors require to bear the risks associated with speculative grade

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[54] Standard & Poor's, *Corporate Ratings Criteria* at 9, available at www.standaredandpoors.com/ratings.
[55] *Id.* at 8.

credit ratings. While average yields on double-B public utility bonds are not routinely published, Moody's recently reported that the average yield on speculative-grade debt securities exceeded prevailing yields on long-term government bonds by 387 basis points during the period 1993 through 1997.[57] Since that time, however, the number of downgrading actions affecting below investment grade debt accelerated as the economy weakened and uncertainties increased. As a result, the speculative-grade yield spread widened sharply to an average of 666 basis points from year-end 1997 through the first quarter of 2003,[58] before narrowing to 403 basis points in December 2003. The table below calculates the implied risk premium for speculative grade debt based on current long-term government and industrial bond yields:

	1993-1997	**1997-1st Q 2003**	**Dec. 2003**
Speculative Grade Yield Spread	3.87%	6.66%	4.03%
Dec. 2003 Long-term Govt. Bond Yield	5.15%	5.15%	5.15%
	9.02%	11.81%	9.18%
Less:			
Dec. 2003 Average Industrial Bond Yield	6.04%	6.04%	6.04%
Implied Risk Premium	**2.98%**	**5.77%**	**3.14%**

Based on this evidence, the capital markets would require approximately 3.0 to 5.8 percent in additional return in order to compensate for the greater risks associated with speculative grade debt instruments. 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 below investment grade rating.

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[56] Moody's Investors Service, "Tracing the Origins of Investment Grade," *Special Comment* (Jan. 2004) at 6.
[57] Moody's Investors Service, *Credit Perspectives* (Jul. 14, 2003) at 35.
[58] *Id.*

Q. What does this evidence suggest with respect to Avista's cost of equity relative to the proxy group of electric utilities?

A. Because of the additional investment risks associated with Avista's speculative grade corporate ratings and the Company's weakened credit standing and financial flexibility, investors' required rate of return on equity for Avista exceeds that of the benchmark group of electric utilities. Considering the evidence presented earlier, a rate of return on equity from the uppermost end of my 10.4 to 11.9 percent range is justified to support Avista's continued progress in improving its financial health and flexibility and, ultimately, an investment grade credit rating. Denying investors the opportunity to earn a return that is commensurate with Avista's investment risks would perpetuate the Company's anemic credit standing and hamper its ability to attract capital on reasonable terms.

C. 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, a utility's ability to fulfill its mandate can be compromised if it lacks the necessary financial wherewithal.

Q. What lessons can be learned from recent events in the energy industry?

A. Events in the western U.S. provide a dramatic illustration of the high costs that all stakeholders must bear when a utility's financial integrity is compromised. California's failed regulatory structure and its impact throughout the west led to unprecedented volatility in wholesale power costs. For many utilities, recovery of purchased energy costs that they were forced to buy to serve their customers was either prevented and/or postponed. As a result, they were denied the opportunity to earn risk equivalent rates of return and access to capital was cut off. Regional economies have been jolted and consumers have suffered the results of higher cost power and reduced reliability. Moreover, while the impact of the utilities' deteriorating financial condition was felt swiftly, stakeholders have discovered first hand how difficult and complex it can be to remedy the situation after the fact.

Q. Do you have any personal experience regarding the damage to customers that can result when a utility's financial integrity deteriorates?

A. Yes. I was a staff member of the Public Utility Commission of Texas when the financial condition of El Paso Electric Company ("EPE") began to suffer in the late 1970s. I later observed first-hand the difficulties in reversing this slide as a consultant to Asarco Mining, EPE's largest single customer. EPE's ultimate bankruptcy imposed enormous costs on customers and absorbed an undue amount of the PUCT's resources, as well as those of the Attorneys General and other state agencies. Now I am serving as a consultant to the utility as it completes a long struggle to fully recover its financial health. There is no question that customers and other stakeholders would have been far better off had EPE avoided bankruptcy by maintaining the utility's financial resilience.

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

A. Once lost, investor confidence is difficult to recover and the damage is not easily reversible. 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 over a period of time.

Given that Avista's corporate credit rating is already below investment grade, the perception of a lack of regulatory support could lead to further downgrades or, at a minimum, prolong Avista's efforts to achieve investment grade ratings. Moreover, the negative impact of declining credit quality on a utility's capital costs and financial flexibility becomes more pronounced as debt ratings move down the scale from investment to non-investment grade.

At the same time, Avista's long-term plans include significant plant investment to ensure that the energy needs of its service territory are met and that customers and the Company are insulated from exposure to the vagaries of competitive wholesale markets. While providing the infrastructure necessary to meet the energy needs of customers is certainly desirable, it imposes additional financial responsibilities on Avista. To meet these challenges successfully and economically, it is crucial that Avista receive adequate support to improve its credit standing.

D. Other Factors

Q. What else should be considered in evaluating the relative risks of Avista?

A. Because close to one-half of Avista's total energy requirements are provided by hydroelectric facilities, the Company is exposed to a level of uncertainty not faced by most utilities, which are less dependent on hydro generation. While hydropower confers advantages in terms of fuel cost savings and diversity, investors also associated hydro facilities with risks that are not encountered with other sources of generation. Reduced hydroelectric generation due to below-average water conditions forces Avista to rely more heavily on purchased power or efficient thermal generating capacity to meet its resource needs. As noted earlier, in the minds of investors, this dependence on wholesale markets entails significant risk, especially for a utility located in the west. The ongoing risks associated with uncertainty in western power markets has been recognized by the Commission, which voiced its concern "about the unknown water and market conditions that lie ahead" and noted that "as we have learned over the past two years, there are no guarantees about future stream flows or market prices.[59] Similarly, S&P recently observed that:

> Utilities in the Pacific Northwest continue to face a host of challenges. If the western power crisis left a large number of them, investor-owned as well as publicly-owned, in dire financial straits, weak economic conditions and the uncertain hydro situation have hampered recovery prospects.[60]

S&P went on to note the significant potential costs and risks imposed by uncertainty over fish-conservation measures that might be required to meet federal law and continued volatility in wholesale power markets, concluding that "managing hydro risk has assumed a critical importance to credit quality."[61]

Q. What other factors would investors likely consider in evaluating their required rate of return for Avista?

A. Investors have clearly recognized that structural change and market evolution in the electric power industry have led to a significant increase in the risks faced by industry participants. For a firm caught between expanding wholesale competition in the industry and the constraints of regulation, as are electric utilities, these risks are further magnified. As S&P recognized:

> Although the move to competition from regulation is obviously negative for credit quality in general, the transition period can often be worse for

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[59] *Idaho Power granted $256 million deferral, but bond plan denied*, Idaho Public Utilities Commission (May 13, 2002).
[60] Standard & Poor's Corporation, "Legal Developments Add to Utilities' Disquiet in U.S. Northwest," *Utilities & Perspectives* (July 21, 2003) at 2-3.
[61] *Id.*

> bondholders than would be a fully competitive industry. In the interim, companies can be saddled with many of the disadvantages of being regulated (*e.g.*, limits on return on capital and higher costs to comply with regulatory mandates) while simultaneously being gradually exposed to marketplace risks.[62]

Similarly, the Wall Street Journal highlighted the risks that investors associate with the interface between competition and regulation in the power industry:

> Now, with the power industry hovering uneasily between regulation and deregulation, it faces the prospect of a market that combines the worst features of both: a return to government restrictions, mixed with volatility and price spikes as companies struggle to meet the nation's energy needs.[63]

Moreover, investors recognize that regulation has its own risks. In some circumstances regulatory uncertainty can eclipse all of the other risk factors facing particular utilities. Considering the magnitude of the events that have transpired since the third quarter of 2000, investors' sensitivity to market and regulatory uncertainties has increased dramatically. The sharpened focus on the risks associated with unrecoverable wholesale power costs, for example, 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.[64]

Investors' required rates of return for utilities are premised on the regulatory compact that allows the utility an opportunity to recover reasonable and prudently incurred costs. By sheltering utilities from exposure to extraordinary power cost volatility, ratepayers benefit

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[62] Standard & Poor's, CreditWeek, Nov. 1, 2000, at 31.
[63] Rebecca Smith, *Shock Waves*, The Wall Street Journal, Nov. 30, 2001, at A1.
[64] Regulatory Research Associates, "Recovery of Wholesale Power Costs: Who is at Risk and Who is Not?", *Regulatory Focus*, p. 1 (February 28, 2001).

from lower capital costs than they would otherwise bear. Of course, the corollary implies that, if investors believe that the utility might face continued exposure to potentially extreme fluctuations in power supply costs while remaining obligated to provide service at regulated rates, their required return would be considerably increased. As S&P noted, the August 14th blackout is unlikely to ease investors' concerns:

> Clearly, the blackout has highlighted the complexity of the system, the diversity of its many stakeholders and the susceptibility of the industry to political and regulatory risk.[65]

E. Conclusions

Q. What is your conclusion regarding the 11.5 percent ROE requested by Avista in this case?

A. Based on the capital market research presented earlier, I concluded that a fair rate of return on equity for the proxy group of electric utilities was in the 10.4 to 11.9 percent range. In evaluating the rate of return for Avista, it is important to consider investors' continued focus on the unsettled conditions in restructured wholesale power markets, the Company's ongoing reliance on these markets to purchase a portion of its energy supply, as well as other risks associated with the power industry, such as heightened exposure to regulatory uncertainties. In addition, Avista's below-investment grade credit rating implies a level of investment risk that exceeds that of the proxy group used to estimate the cost of equity. This suggests that, at a minimum, Avista's required rate of return on equity falls at the uppermost end of my 10.4 to 11.9 percent range for the firms in the benchmark group of western electric utilities. Considering the economic requirements and risks discussed above, it is my conclusion that the 11.5 percent ROE represents a conservative estimate of investors' required rate of return for Avista in today's capital markets.

Q. How does Avista's requested 11.5 percent return on equity compare with other benchmarks that investors would consider?

A. Reference to rates of return available from alternative investments can also provide a useful guideline in assessing the return necessary to assure confidence in the financial integrity of a firm and its ability to attract capital. This comparable earnings approach avoids the complexities and limitations of capital market methods and instead focuses on the returns earned on book equity, which are readily available to investors.

Value Line's most recent projections indicate that its analysts expect average rates of return on common equity for the electric utility industry over the next three to five years of 11.0 percent,[66] with rates of return for gas distribution utilities expected to average 11.5 percent.[67] Meanwhile, the firms included in Value Line's Composite Index are expected to earn 16.0 percent on book equity during the 2006-2008 time frame.[68] Considering Avista's higher risk profile, these expected earned rates of return confirm the reasonableness of the Company's request.

Avista's requested rate of return is further supported by the fact that investors are likely to anticipate increases in utility bond yields going forward. Moreover, an 11.5 percent rate of return on equity is reasonable at this critical juncture, given the importance of

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[65] Standard & Poor's Corporation, "Electric Utility Blackout Puts Spotlight on Political and Regulatory Credit Risk," *RatingsDirect* (Aug. 21, 2003).
[66] The Value Line Investment Survey (Jan. 2, 2003) at 695.
[67] The Value Line Investment Survey (Dec. 19, 2003) at 458.
[68] The Value Line Investment Survey, *Selection & Opinion* (July 18, 2003) at 2857.

supporting the financial capability of Avista as it prepares to develop and enhance utility infrastructure. As the summer power failures amply demonstrated, the cost of providing Avista an adequate return is small relative to the potential benefits that a strong utility can have in providing reliable service. Considering investors' heightened awareness of the risks associated with the electric power industry 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.

Q. Does this conclude your pre-filed direct testimony?

A. Yes.

APPENDIX A

QUALIFICATIONS OF WILLIAM E. AVERA

WILLIAM E. AVERA

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

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Austin, Texas 78751
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Summary of Qualifications

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

Employment

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

Financial, economic and policy consulting to business and government. Perform business and public policy research, cost/benefit analyses and financial modeling, valuation of businesses (over 100 entities valued), estimation of damages, statistical and industry studies. Provide strategy advice and educational services in public and private sectors, and serve as expert witness before regulatory agencies, legislative committees, arbitration panels, and courts.

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

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

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

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

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

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

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

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

Education

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

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

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

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

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

Professional Associations

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

Teaching in Executive Education Programs

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

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

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

Expert Witness Testimony

Testified in nearly 200 cases before regulatory agencies addressing 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, Arizona, Arkansas, California, Colorado, Connecticut, Delaware, Florida, Hawaii, Idaho, Illinois, Indiana, Kansas, Maryland, Michigan, Missouri, Nevada, New Mexico, North Carolina, Ohio, Oklahoma, Oregon, Pennsylvania, South Carolina, Texas, Virginia, Washington, West Virginia, and Wisconsin.

Testified in over 30 cases before federal and state courts, arbitration panels, and alternative dispute tribunals (over 60 depositions given) regarding damages, valuation, antitrust liability, fiduciary duties, and other economic and financial issues.

Board Positions and Other Professional Activities

Audit Committee and Outside Director, Georgia System Operations Corporation (electric system operator for member-owned electric cooperatives in Georgia); Chairman, Board of Print Depot, Inc. and FINCAP, Inc.; Co-chair, Synchronous Interconnection Committee, appointed by Governor George Bush and Public Utility Commission of Texas; Operator of AAA Ranch, a certified organic producer of agricultural products; Appointed to Organic Livestock Advisory Committee by Texas Agricultural Commissioner Susan Combs; Appointed by Texas Railroad Commissioners to study group for *The UP/SP Merger: An Assessment of the Impacts on the State of Texas;* Appointed by

Hawaii Public Utilities Commission to team reviewing affiliate relationships of Hawaiian Electric Industries; Chairman, Energy Task Force, Greater Austin-San Antonio Corridor Council; Consultant to Public Utility Commission of Texas on cogeneration policy and other matters; Consultant to Public Service Commission of New Mexico on cogeneration policy; Evaluator of Energy Research Grant Proposals for Texas Higher Education Coordinating Board.

Community Activities

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

Military

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

Bibliography

Monographs

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

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

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

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

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

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

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

Articles

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

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

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

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

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

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

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

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

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

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

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

Selected Papers and Presentations

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

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

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

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

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

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

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

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

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

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

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

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

"The Regulators' Perspective," Bellcore Economic Analysis Conference, San Antonio (Nov. 1987)

"Public Utility Commissions and the Nuclear Plant Contractor," Construction Litigation Superconference, Laguna Beach, California (Dec. 1986)

"Development of Cogeneration Policies in Texas," University of Georgia Fifth Annual Public Utilities Conference, Atlanta (Sep. 1985)

"Wheeling for Power Sales," Energy Bureau Cogeneration Conference, Houston (Nov. 1985).

"Asymmetric Discounting of Information and Relative Liquidity: Some Empirical Evidence for Common Stocks" (with John Groth and Kerry Cooper), Southern Finance Association, New Orleans (Nov. 1982)

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

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

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

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

"The Relative Value of Statistics of Ex Post Common Stock Distributions to Explain Variance," with Charles G. Martin, Southern Finance Association, Atlanta (Nov. 1977)

"An ANOVA Representation of Common Stock Returns as a Framework for the Allocation of Portfolio Management Effort," with Charles G. Martin, Financial Management Association, Montreal (Oct. 1976)

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

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

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

"Multi-period Wealth Distributions and Portfolio Theory," Southern Finance Association, Houston (Nov. 1973)

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