BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC SERVICE TO ELECTRIC CUSTOMERS IN THE STATE OF IDAHO.	)))))))	CASE NO. IPC-E-03-13

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

WILLIAM E. AVERA

TABLE OF CONTENTS

(For Convenience of Reader)

I. INTRODUCTION

Q. Please state your name and business address.

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

Q. What is your present occupation?

A. I am a financial, economic, and policy consultant to business and government.

A. <u>Qualifications</u>

Q. What are your 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").

With the approval of then-Governor George W. Bush, I was appointed by the PUCT to the Synchronous Interconnection Committee to advise the Texas legislature on the costs and benefits of connecting Texas to the national electric transmission grid. Currently, I 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 have also served on the Board of Directors of the North Carolina Society of Financial Analysts. I was elected Vice Chairman of the National Association of Regulatory Commissioners ("NARUC") Subcommittee on Economics and appointed to NARUC's Technical Subcommittee on the National Energy Act. I have also served as an officer of various other professional organizations and societies. A resume containing the details of my experience and qualifications is attached as Exhibit No. 11.

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 a fair rate of return on equity ("ROE") range for Idaho Power Company's Idaho jurisdictional electric utility operations.

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

A. To prepare my testimony, I used information from a variety of sources that would customarily be relied on by a person in my area of expertise. I am familiar with the organization and operations of Idaho Power from my prior participation before the Commission on behalf of the Company in Case No. IPC-E-94-5. In connection with the present filing, I considered information relevant to Idaho Power obtained through discussions with corporate management and from my review of numerous documents relating to the Company and its parent, IDACORP, Inc. ("IDACORP"). These included financial reports and filings, prior regulatory proceedings and orders, as well as bond rating agency reports. I also reviewed information relating generally to current capital market conditions and specifically to investor perceptions, requirements, and expectations for vertically integrated electric utilities like Idaho Power. These sources, coupled with my experience in the fields of finance and utility regulation, have given me a working knowledge of investors' ROE requirements confronting Idaho Power 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* [*Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n,* 262 U.S. 679 (1923)] and *Hope* [*Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944)] 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 on equity range for Idaho Power?

A. I first reviewed the operations and finances of Idaho Power 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 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 relative strengths and weaknesses of the alternative methods, as well as other factors (*e.g.*, flotation costs) that are properly considered in setting the ROE for Idaho Power's electric utility operations in Idaho.

C. <u>Summary of Conclusions</u>

Q. Please summarize your findings regarding the fair rate of return on equity for Idaho Power.

A. My quantitative analyses of the cost of equity included applications of the DCF model and risk premium methods to a benchmark group of eight electric utilities operating in the western U.S. Based on the results of these approaches, I concluded that the fair rate of return on common equity for Idaho Power is presently in the range of 10.6 to 11.9 percent.

In evaluating the ROE for Idaho Power, it is important to consider investors' continued focus on the unsettled conditions in western power markets and the unique risks imposed by the Company's much greater reliance on hydroelectric generation to meet its energy needs. Regulatory uncertainties, along with unfavorable capital market conditions, compound the investment risks associated with the jurisdictional utility operations of Idaho Power. Coupled with investors' expectations for higher utility bond yields going forward, these greater risks support the reasonableness of my 10.6 to 11.9 percent ROE range.

The cost of fully funding the Company's return on common equity is small relative to the potential benefits that a financially sound utility can have in providing reliable service at reasonable rates and supporting economic growth. Considering the importance of ensuring investor confidence and maintaining Idaho Power's financial flexibility and the ability to attract needed capital, an ROE in the 10.6 to 11.9 percent range is both necessary and reasonable at this critical juncture.

II. FUNDAMENTAL ANALYSES

Q. What is the purpose of this section?

A. This section 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 that drive the risks and prospects of electric utilities is essential to developing an informed opinion about current investor expectations and requirements that form the basis of a fair rate of return on equity. In addition, as a predicate to my economic and capital market analyses, this section briefly describes Idaho Power and reviews its operations and finances.

A. Idaho Power Company

Q. Briefly describe Idaho Power.

A. Headquartered in Boise, Idaho Power is a wholly-owned subsidiary of IDACORP and is principally engaged in providing integrated retail electric utility service in a 20,000 square mile area in southern Idaho and eastern Oregon. During the most recent fiscal year, Idaho Power's energy deliveries totaled 15.0 million megawatt hours ("mWh"). Sales to residential customers comprised 34 percent of retail sales, with 27 percent to commercial, 25 percent to industrial end-users, and 14 percent attributable to irrigation pumping. Idaho Power also supplies firm wholesale power service to various utilities and municipalities, as well as three large customers under sales contracts. Idaho Power's service area has experienced strong population growth, expanding over 10 percent in the last decade compared with the national average of 3.8 percent.

At year-end 2002, Idaho Power had total assets of $2.7 billion and during the most recent fiscal year total electric revenues amounted to approximately $867 million. Principal industries in the area include food processing, lumber, electronics and general manufacturing, fertilizer production, and year-round recreational facilities, such as those in the Sun Valley resort area. Idaho Power anticipates total capital expenditures of approximately $675 million over the next three years. The Company recently approved a development contract, subject to Commission approval, for construction of a 160 megawatt ("MW") gas-fired generating plant near Mountain Home, Idaho. Total cost of the project, which includes plant construction and necessary transmission system upgrades, is $61 million, with Idaho Power taking ownership once the facility has been fully tested and operational. In order to provide additional support for its capital expenditure program, Idaho Power's Board of Directors ("Board") voted to cut its common stock dividends for the next quarter by more than $6 million, prompting IDACORP to announced that it was reducing annual common dividends some 35 percent from $1.86 to $1.20 per share.[1]

With a combined capacity of approximately 3,117 MW, Idaho Power's existing generating units include 17 hydroelectric generating plants located in southern Idaho and interests in three coal-fired plants located in Oregon, Nevada, and Wyoming. During 2002, company-owned generation accounted for 82.1 percent of the electric energy provided by Idaho Power, with the balance being obtained through power purchases. The electrical output of its hydroelectric plants is dependent on streamflows, which have fallen below normal levels for the last three years. As a result, approximately 45 percent of Idaho Power's total system generation in 2002 was provided by hydroelectric generation, as compared with 57 percent under normal conditions. Snowpack and upstream reservoir storage for 2003 have fallen below measurements for the previous year and Idaho Power is experiencing its fourth consecutive year of below-normal water conditions.

Idaho Power's transmission system interconnects the Company with other western electric utilities. Coupled with Idaho Power's membership in the Western Electricity Coordinating Council, the Western Systems Power Pool, the Northwest Power Pool and the Northwest Regional

Transmission Association, these transmission interconnections permit the interchange, purchase, and sale of power among all major electric systems in the west.

Idaho Power is subject to state retail regulation in Idaho and Oregon and at the federal level by FERC. Additionally, Idaho Power's hydroelectric facilities are subject to licensing under the Federal Power Act, which is administered by FERC, as well as the Oregon Hydroelectric Act. Currently, the permanent licenses for five of Idaho Power's hydroelectric facilities have expired. Idaho Power is actively seeking relicensing under a process that could continue for up to 15 years. Relicensing is not automatic under federal law, and Idaho Power must demonstrate that it has operated its facilities in the public interest, which includes adequately addressing environmental concerns. The most significant of Idaho Power's relicensing efforts concerns its Hells Canyon Complex, which represent 68 percent of the Company's hydro capacity and 40 percent of its total generating capability. After a prolonged period of planning and consultation with interested parties, Idaho Power has developed a draft license application that includes various protection, mitigation, and enhancement measures in order to address environmental concerns while preserving the peak and load following operations of the facilities. The estimated cost of these measures is $78 million in the first five years of the license.

Q. How are fluctuations in Idaho Power's operating expenses caused by varying hydro and power market conditions accommodated in its rates?

A. Beginning in May 1993, Idaho Power implemented a power cost adjustment mechanism ("PCA"), under which rates are adjusted annually 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 Idaho Power 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 annually, it applies to 90 percent of the deviation between actual power supply costs and normalized rates. As a result, the net amount of power supply costs not recovered through the PCA mechanism totaled approximately $55.2 million over the past three years.

Q. What credit ratings have been assigned to Idaho Power and its parent, IDACORP?

A. Idaho Power and its parent, IDACORP are both currently assigned a corporate credit rating of "A-" by Standard & Poor's Corporation ("S&P"). Meanwhile, Moody's Investors Service ("Moody's) has assigned issuer credit ratings of “A3” and “Baa1” to Idaho Power and IDACORP, respectively. S&P recently revised its outlook on both companies downward from “positive” to “stable”, primarily due to expected weakness attributable to Idaho Power’s ongoing recovery of deferred power costs, poor water conditions, and lower than expected sales.[2]

B. Electric Power Industry

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

A. For almost twenty years, electric utilities and their consumers have enjoyed a respite from the volatility characteristic of the late 1970s and early 1980s. More recently, however, these general economic factors have been overshadowed by structural changes in the electric utility industry resulting from market forces, decontrol initiatives, and judicial decisions.

Q. Please describe these structural changes.

A. At the federal level, 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[3] and through subsequent policy statements.[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.

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 has led to the disaggregation of many formerly integrated electric utilities into three primary components - generation, transmission, and distribution. Presently, however, Idaho Power is, and is expected to remain, a fully integrated public utility.

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, which originated in California, has wreaked havoc on the region'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 California 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 now 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 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.[5]

While the case of California and PG&E represents an extreme example, there is every indication that investors' risk perceptions for electric utilities have shifted sharply upward as events in the western U.S. continued to unfold. The resolution is far from over, as even today, FERC, federal and state courts, and other agencies continue their investigations to determine 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 a 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. The fourth quarter of 2002 alone witnessed 48 downgrades as the negative pressure on utility creditworthiness continued unabated.

Q. What is 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, have 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.[6]

> 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.[7]

In light of the challenges faced by electric utilities, financing activity actually declined some 14 percent in 2002, with many utilities being forced to rely increasingly 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 the falloff in financing activity was partly attributable to "capital market jitters, especially for those firms that are most in need of capital market access."[8] As a result, at the same time that industry uncertainty and market volatility has increased the importance of financial flexibility, electric utilities are facing limited access and higher costs for the capital required to maintain sufficient liquidity. Moreover, credit quality has continued to decline. S&P reported an unprecedented 88 ratings downgrades during the first half of 2003 alone, an acceleration of the downward trend witnessed during the previous year.[9] Similarly, Moody's downgraded 51 utilities between January and June 2003, while upgrading only one firm.[10] S&P also noted that constrained access to capital markets and investor skepticism was contributing to the bleak credit picture.[11]

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

A. Like others, Idaho Power was swept up in the maelstrom of the western energy crisis in 2000 and 2001. Because of Idaho Power's dependence on hydroelectric generation, it has always faced the uncertainties associated with year-to-year fluctuations in water conditions. Nevertheless, the degree of price volatility that participants in the western power markets were forced to assume was unprecedented and variability in short-term market prices bore no resemblance to fluctuations encountered 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, Idaho Power had recorded a regulatory asset of $290 million related primarily to power cost deferrals resulting from low hydroelectric generation and higher purchased power prices.[12] 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.[13]

Even for electric utilities such as Idaho Power 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. [14]

Because Idaho Power was dependent on wholesale power markets in the west to meet the gap in its resource needs created by reduced hydro generation, the chaotic market conditions were felt directly. The continuing prospect of further turmoil in western power markets cannot be discounted. From the standpoint of the capital markets, the west is risky - and Idaho Power's exposure to wholesale markets in meeting shortfalls in hydroelectric generation compounds these uncertainties.

Investors recognize that volatile markets, unpredictable stream flows, and Idaho Power's dependence on wholesale purchases to meet the needs of its customers can create a “perfect storm”, exposing the Company to the risk of reduced cash flows and unrecovered power supply costs. In response to the risks inherent in substantial reliance on wholesale power markets for electricity supply, and recognizing the continuing uncertainty concerning the availability of hydroelectric generation, Idaho Power has proposed a plan to expand its electric utility system, including the construction of additional generating resources at Mountain Home. Accordingly, maintaining Idaho Power’s financial integrity and flexibility will be instrumental in attracting the capital necessary to fund these projects in an effective manner.

Q. What are the implications of the recent power outages recently experienced in the upper Midwest and Northeast?

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 galvanized the attention of all industry stakeholders - utilities, consumers, regulators, and investors - on the urgent 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.[15]

Indeed, as noted earlier, Idaho Power is committed to expanding the scope and reliability of its utility system in order to provide customers with reliable service 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 Idaho Power?

A. Absolutely. While electric utility restructuring has not been actively pursued in Idaho, the Company continues to face the prospect of FERC-driven changes in the transmission sector of their business, as well as fundamental reforms in the operation of wholesale markets.[16] Idaho Power is an active participant in the formation of a proposed RTO ("RTO West"), an independent entity that will operate the transmission grid in seven western states. While RTO West received Stage II approval from FERC, substantial additional filings will be necessary before federal and state approval are received.

Indeed, the pace of policy evolution in the transmission area has been brisk. 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 reliability and increase capacity in the future. Uncertainty will exist until operating rules are in place and have stabilized.[17]

Virtually all industry stakeholders have recognized that regulatory uncertainty increases the risks associated with the electric industry. FERC Commissioner Massey says that regulatory uncertainty is "part of the problem" explaining under-investment in electric utility infrastructure.[18] 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.[19] 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.[20]

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."[21] Similarly, while the Consumer Energy Council of America recognized that improvements in electric utility infrastructure are necessary to ensure reliability and support the economy, they concluded that regulatory uncertainty "has contributed to a fear of instability for the entire system".[22]

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.[23] Similarly, FERC Chairman Wood concluded in his initial comments on the power outages that:

> Clearly, we need regulatory certainty and other incentives for investment.[24]

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."[25] 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.[26]

Because of potential dependence on wholesale markets, the risks of transmission uncertainties and potential market volatility are intensified for utilities that must meet shortfalls in resource needs through power purchases. Thus, Idaho Power's greater dependence on hydroelectric generation, which fluctuates with changes in streamflows, exposes the Company and its investors to the ongoing regulatory uncertainties and other risks imposed by federal restructuring of wholesale power markets and magnifies the importance of maintaining financial flexibility.

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

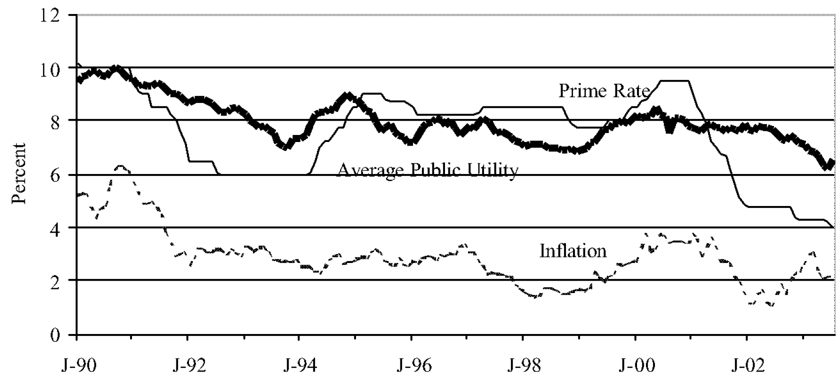
A. No. Apart from these factors, the industry continues to face the normal risks inherent in operating electric utility systems, including the potential adverse effects of inflation, interest rate changes, growth, and regulatory uncertainty and lag. Electric utilities are confronting increased environmental 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.[27]

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 6.8 percent from average public utility bonds in August 2003:



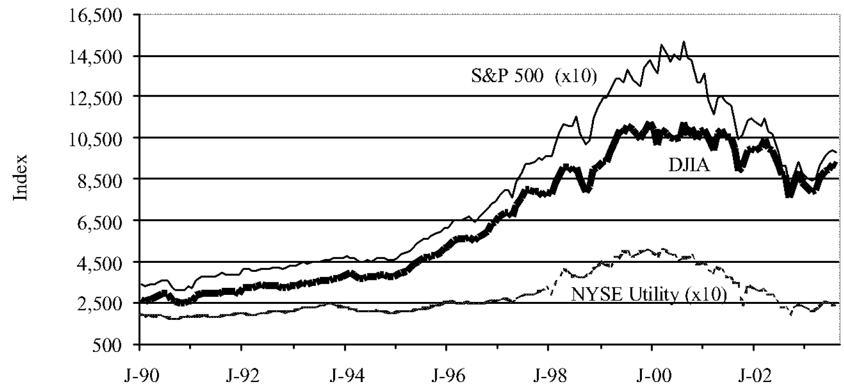
Q. Are investors likely to anticipate any substantial decline in interest rates going forward?

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 November 20, 2002, anticipates that the double-A public utility bond yield will increase from 6.90

percent in 2002 to 8.10 percent by 2005, with the average being 7.49 percent over the next 10 years.[28] Similarly, the most recent long-term projections from *GlobalInsight* (formerly DRI/WEFA) anticipate that public utility bond yields will increase to 8.19 percent by 2007 and average approximately 7.8 percent over the intervening years.[29]

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 equity prices have recovered from recent lows, the market has become increasingly 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):



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 have been exemplified by the Federal Reserve's sequential lowering of interest rates. The economy continues to chart an uneven course, corporate profits remain under pressure, capital spending continues to be weak, and businesses have been reluctant to expand hiring. More recently, uncertainties over the fragility of the economy have been magnified by the aftermath of war in Iraq and ongoing instability in the Middle East, 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.	The weakened state of the economy and the uncertainty of 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 recovery 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 common shares. 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 paid 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 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, however, is complicated by two factors. First, there is no standard measure of risk applicable to all assets. Second, for most assets - including common stock - required rates of return cannot be directly observed. 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.

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 (or bonds), 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, they may force it into bankruptcy. Following first mortgage bonds are other debt instruments also holding contractual claims on the utilities 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. Because cash flows to common shareholders are not contractually defined, dividend payments may be eliminated altogether or substantially reduced, as illustrated by the recent actions of Idaho Power’s Board and IDACORP. As a result, the rate of return that investors require from a utility’s common stock, the most junior and riskiest of its securities, is considerably higher than the yield 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 Idaho Power?

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.[30]

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 may be a reasonable working approximation of stock valuation that can provide useful insight as to investors' required rate of return.

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

A. Application of the DCF model directly to Idaho Power is hindered because, as a wholly-owned subsidiary, the Company does not have publicly traded common stock. Meanwhile, as discussed earlier, Idaho Power and, in turn, IDACORP recently elected to cut common dividend payments significantly in order to improve cash flow and help maintain the strong credit ratings necessary to support the Company's capital expansion plan. 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 DCF methods, this approach is not well-suited for firms that do not pay common dividends or have recently cut their payout.

As an alternative, the cost of equity is often estimated by applying the DCF model to publicly traded companies engaged in the same business activity. In order to reflect the risks and prospects associated with Idaho Power'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 four firms that do not pay common dividends and two that were rated below investment grade by S&P.[31] 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, as the Electric Consumers Resource Council recently reported:

> The West is different than the East in terms of electricity grid operations, according to Marsha Smith, a Commissioner with the Idaho Public Utilities Commission and Chair of (NARUC). ... The vast geographic areas served by western utilities mean electricity is being transmitted over much longer distances that in other regions, particularly the East, and there are fewer customers per mile of transmission line, resulting in greater line loss, Ms. Smith said.
>
> She also said the West's reliance on hydroelectric energy makes planning more difficult than in the East. Hydropower cannot be forecast, and the amount of winter snow determines how much may be shipped each spring and summer to power-dependent areas such as California. Reliance on hydropower makes long-term planning difficult and plays havoc with the day-ahead market, envisioned in FERC's proposed standard market design (SMD) rule.[32]

Indeed, as noted earlier, the uncertainties associated with relying on hydroelectric generation is an important consideration in evaluating investors' required rate of return for Idaho Power.

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

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.[33]

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.

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 Idaho Power, 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 that extent 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 <u>what investors expect</u> 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 Exhibit No. 5. As shown there, dividend yields for the eight firms in the electric utility proxy group ranged from 3.2 percent to 6.0 percent, with the average being 4.4 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.

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

A. No. While the dividend yield is an important component of DCF applications and investors look to dividends as one indicator of a firm's financial health, trends in dividends are unlikely to reflect the long-term "*g*" presumed by the DCF model. As illustrated by the recent decision of the Board and IDACORP to significantly reduce their payout, dividend policies for electric utilities have become increasingly conservative as business risks in the industry have become more accentuated. Thus, while earnings may be expected to grow significantly, dividends have remained largely stagnant as utilities conserve financial resources to provide a hedge against heightened uncertainties. 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 65 percent.[34] 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.

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.[35]

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%.[36]

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.[37] 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:

> Earnings and cash flow are considered far more important than book value and dividends.[38]

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 <u>Earnings Guide</u> are shown on Exhibit No. 6. 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 5.0 to 5.5 percent for the reference group of electric utilities:

Electric Utility Proxy Group

Service	**Growth Rate**
IBES	5.3%
Value Line	2.7%
First Call	5.5%
Multex	5.0%

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"[39] and that:

> …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.[40]

Value Line 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 89. 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 Exhibit No. 6. 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 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 Exhibit No. 7. 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 4.7 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, First Call, and Multex, as well as past experience.

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

A. Combining the 4.4 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 10.4 percent.

C. <u>Risk Premium Analyses</u>

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 Idaho Power 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 electric utility 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,[41] 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.

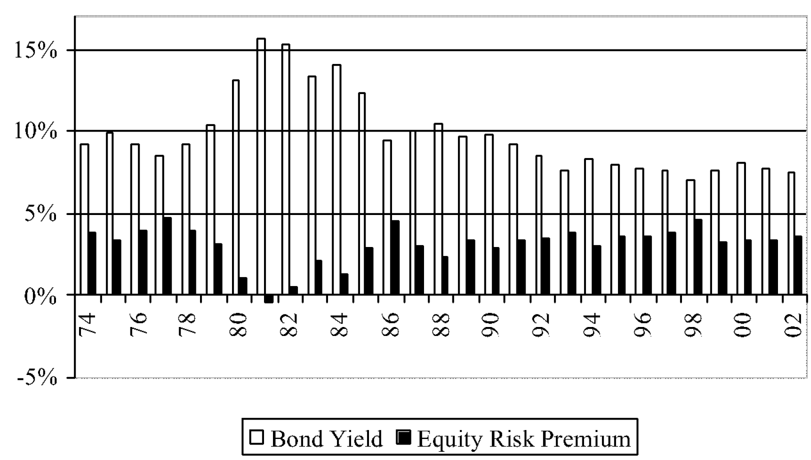
While these methods are premised on different assumptions, each having their own strengths and weaknesses, they are widely accepted approaches that have been routinely referenced in estimating the cost of equity for regulated utilities.

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 Exhibit No. 8, 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.

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 (shaded bars) and equity risk premiums (solid bars) shown on Exhibit No. 8:



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 Exhibit No. 8, 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 shown there, with the yield on public utility bonds in August 2003 being 302 basis points lower than the average for the study period, this implied a current equity risk premium of 4.39 percent for electric utilities. Adding this equity risk premium to the August 2003 yield on single-A public utility bonds of 6.79 percent implies a current cost of equity for Idaho Power 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.[42] 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. Exhibit No. 9 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 August 2003 yield of 6.79 percent on single-A public utility bonds suggests a current cost of equity for Idaho Power of approximately 10.8 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:

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

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.

Exhibit No. 10 presents an application of the CAPM to the eleven 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 5.39 percent risk-free rate based on the August 2003 average yield on 20-year government bonds from the 14.24 percent forward-looking rate of return produced a market equity risk premium of 8.85 percent. Multiplying this risk premium by the average Value Line beta of 0.71 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 Return on Equity**

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

A. Consistent with the results of my quantitative analyses, I concluded that the cost of equity for the proxy group is presently in the 10.4 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.[43]

Applying these expense percentages to a representative dividend yield for an electric utility of 4.4 percent implies a flotation cost adjustment on the order of 20 to 40 basis points.

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 10.6 to 11.9 percent range.

IV. RETURN ON EQUITY FOR IDAHO POWER COMPANY

Q. What is the purpose of this section?

A. This section addresses the economic requirements for Idaho Power's return on equity. It examines other factors properly considered in determining a fair rate of return, such as market perceptions of Idaho Power'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 Idaho Power's requested capital structure?

A. Idaho Power's capital structure is presented in the testimony of Dennis C. Gribble. As summarized in his testimony, the common equity ratio used to compute Idaho Power's overall rate of return was approximately 44.7 percent.

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

A. For the eight firms in the Electric Utility (West) group, common equity ratios at year-end 2002 ranged from 37.4 percent to 60.6 percent and averaged 45.8 percent.

Q. How does Idaho Power'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 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.

Consistent with S&P's current guidelines and Idaho Power's S&P *business profile* ranking of "4", a utility would be required to maintain a ratio of total debt to total capital of 46.0 percent to qualify for a single-A bond rating.[44] This benchmark equates to total equity ratio of 54.0 percent.

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

A. The challenges imposed by evolving structural changes in the industry imply that utilities will be required to incorporate relatively greater amounts of equity in their capital structures. 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 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.[45]

More recently, Value Line reported that the average common equity ratio for all firms in the electric utility industry is expected to increase from 43 percent in 2003 to 50 percent over the next three to five years.[46] Indeed, continued pressure on credit quality in the electric industry is indicative of the need for utilities to strengthen financial profiles to deal with an increasingly uncertain 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.[47]

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

Q. What other indications confirm the reasonableness of Idaho Power's capital structure policies?

A. In the wake of Enron's collapse, bond rating agencies and investors are closely scrutinizing debt levels. For those firms with higher leverage, this intense focus has led 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 have been forced to issue new common equity 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."[48]

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:

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.[49]

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

A. Idaho Power's proposed capital structure is in-line with the ranges maintained by the comparable group of electric utilities, although its equity ratio falls somewhat below the guideline specified by S&P for a single-A rated utility. The reasonableness of Idaho Power's requested capital structure is reinforced by the ongoing uncertainties associated with the electric power industry, the need to support system expansion, and the imperative of maintaining continuous access to capital, even during times of adverse industry and market conditions.

B. Other Factors

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

A. Corporate credit ratings for the eight firms in the Electric Utility (West) group used to estimate the cost of equity range from "BBB-" to "A-". As noted earlier, Idaho Power's senior debt is also currently rated "A-", comparable to the firms in the benchmark group.

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

A. Because approximately one-half of Idaho Power's total energy requirements are provided by hydroelectric facilities, the Company is exposed to a level of uncertainty not faced by other 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 Idaho Power to rely on less efficient thermal generating capacity and purchased power 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. Indeed, the ongoing risks associated with uncertainty in western power markets has been recognized by the Commission. In declining to spread recovery of power cost deferrals over multiple years, the Commission recognized that:

> …the Commission is very concerned about the unknown water and market conditions that lie ahead. …A one-year recovery will take care of nearly all the deferred costs remaining from a sustained period of extraordinarily high wholesale prices at the same time that hydro-dependent Idaho Power customers were experiencing the second worst drought in 75 years. …However, as we have learned over the past two years, there are no guarantees about future stream flows or market prices.[50]

Apart from exposure to market uncertainties, Idaho Power also confronts the complexities associated with obtaining the necessary licenses to operate its hydroelectric stations. The process of relicensing is prolonged and involved and often includes the implementation of various measures to address environmental and stakeholder concerns. These measures can impose significant additional costs and/or lead to reduced generating capacity and flexibility. Moody's recently noted that "[Idaho Power's] rating outlook is negative as the utility continues to cope with difficult power supply markets in its region"[51] and concluded the Company's bond ratings could be reduced based on the following factors:

> Continued delay in return to more normal hydro

> and weather conditions in combination with unexpected harsh treatment from Idaho regulators in the upcoming general rate proceedings. Significant increases in relicensing costs and/or stringent operational constraints impose as part of the license renewal process.[52]

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.[53]

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."[54]

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

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 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.[55]

Similarly, the Wall Street Journal recently 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.[56]

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.[57]

Investors' required rates of return for utilities are premised on the regulatory compact that allows the utility an opportunity to recover reasonable and necessary costs. By sheltering utilities from exposure to extraordinary power cost volatility, ratepayers benefit 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.[58]

C. Implications for Financial Integrity

Q. Why is it important to allow Idaho Power 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 Idaho Power remains committed to deliver reliable electric service at the lowest possible price, a utility's ability to fulfill its mandate can be compromised if it lacks the necessary financial wherewithal.

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 market structure led to unprecedented volatility in the region's 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 PUCT 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 continues its 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 its financial resilience.

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

A. While Idaho Power has been successful in maintaining its financial flexibility, it is important to remember that, 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. Considering investors' sharp focus on the risks associated with the west and the uncertainties imposed by the Company's relative reliance on hydroelectric generation, the perception of a lack of regulatory support would almost certainly lead to a decline in Idaho Power's credit quality and financial flexibility.

At the same time, Idaho Power plans to add significant plant investment, such as the Mountain Home generating facility, to ensure that the energy needs of its service territory are met. While providing the infrastructure necessary to support economic growth is certainly desirable, it imposes significant responsibilities on Idaho Power. To meet these challenges successfully and economically, it is crucial that the Company receive adequate support for its credit standing. Finally, maintaining Idaho Power's access to capital on reasonable terms has the added benefit of preserving the Company's independence and ability to maintain quality service based on the interests of Idaho ratepayers.

D. <u>Conclusions</u>

Q. What is your conclusion regarding a fair rate of return on equity range for Idaho Power?

A. Based on the capital market research presented earlier and the economic requirements discussed above, it is my conclusion that a return on equity in the range of 10.6 to 11.9 percent represents a conservative estimate of investors' required rate of return for Idaho Power in today's capital markets.

In evaluating the rate of return for Idaho Power, it is important to consider investors' continued focus on the unsettled conditions in western power markets. These uncertainties are compounded by the Company's continued reliance on hydroelectric power for a relatively greater portion of its energy supply, as well as other risks associated with the power industry, such as heightened exposure to regulatory uncertainties.

Q. How does your recommended fair rate of return on equity range for Idaho Power 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.

Indeed, the most recent edition of Value Line reports that its analysts expect average rates of return on common equity for the electric utility industry of 11.3 percent and 11.8 percent for 2003 and 2004, respectively, with their three to five year projections anticipating a return on equity of 12.0 percent.[59] Similarly, expected rates of return for gas distribution utilities are expected to average 11.5 percent over Value Line's forecast horizon,[60] while the 696 industrial, retail, and transportation companies included in Value Line's Composite Index are expected to earn 16.0 percent on book equity during the 2006-2008 time frame.[61] Accordingly, these expected earned rates of return confirm the reasonableness of my recommended rate of return on equity range for Idaho Power.

My recommended ROE range is further supported by the fact that investors are likely to anticipate increases in utility bond yields going forward. Moreover, an ROE in the 10.6 percent to 11.9 percent range is reasonable at this critical juncture, given the importance of supporting the financial capability of Idaho Power as it invests the capital that is needed to develop and enhance utility infrastructure. As the recent power failures amply demonstrated, the cost of providing Idaho Power an adequate return is small relative to the potential benefits that a strong utility can have in providing reliable service and fostering growth. 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 direct testimony in this case?

A. Yes, it does.

ENDNOTES

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[3] *Regional Transmission Organizations*, Order No. 2000 (Dec. 20, 1999), 89 FERC ¶ 61,285.

[4] Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design, Notice of Proposed Rulemaking, IV FERC Stats. & Regs. ¶ 32,563 (2002) ("SMD NOPR"); FERC White Paper, Wholesale Power Market Platform, April 28, 2003, available at http://www.ferc.gov/Electric/RTO/Mrkt-Strct-comments/White paper.pdf.

[5] *Remarks by William L. Massey*, Center for Public Utilities Advisory Council, "The Santa Fe Conference" (March 17, 2003).

[6] Standard & Poor's Corporation, *2002 Power & Energy Credit Conference: Beyond the Crisis* (Jun. 12, 2002).

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

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

[15] *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).

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

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

[20] *Id.* at 31.

[21] *Draft Remarks of Kara M. Silva, Vice President, MBIA Insurance Corporation*, NARUC Joint Committee on Electricity, Gas, and Finance and Technology (Feb. 26, 2003).

[22] Consumer Energy Council of America, "Positioning the Consumer for the Future: A Roadmap to an Optimal Electric Power System" (Apr. 2003) at XVII.

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[25] Standard & Poor's Corporation, "Electric Utility Blackouts Put Spotlight on Political and Regulatory Credit Risk", *RatingsDirect* (Aug. 21, 2003).

[26] *Id.*

[27] Standard & Poor's Corporation, *Corporate Ratings Criteria* at 29, available at www.standardandpoors.com/ratings.

[28] Energy Information Administration, *Annual Energy Outlook 2003*, at Table 20, Nov. 20, 2002, *available at* http://www.eia.doe.gov/oiaf/aeo/pdf/aeo_base.pdf.

[29] GlobalInsight, *The U.S. Economy, The 25-Year Focus* (Winter 2003) at Table 33.

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

[31] 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.

[32] *Idaho Commissioner Meets with ELCON*, ELCON Report (No. 2, 2003) at 7.

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

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

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

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[38] *Id.* at 88.

[39] The Value Line Investment Survey (July 4, 2003) at 695.

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

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

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

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[61] The Value Line Investment Survey, *Selection & Opinion* (July 18, 2003) at 2857.