BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION)
OF IDAHO POWER COMPANY FOR)
AUTHORITY TO INCREASE ITS RATES) CASE NO. IPC-E-08-10
AND CHARGES FOR ELECTRIC SERVICE.)
)

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

WILLIAM E. AVERA

DIRECT TESTIMONY OF WILLIAM E. AVERA

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I. INTRODUCTION

Q. Please state your name and business address.

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

Q. In what capacity are you employed?

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

Q. Please describe your educational background and professional experience.

A. I received a B.A. degree with a major in economics from Emory University. After serving in the U.S. Navy, I entered the 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, 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, 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 40 states.

In 1995, 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. In addition, I served 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. 16.

A. Overview

Q. What is the purpose of your testimony in this case?

A. The purpose of my testimony is to present to the Idaho Public Utilities Commission (the "Commission" or "IPUC") my independent evaluation of the fair rate of return on equity ("ROE") for the jurisdictional utility operations of Idaho Power Company ("Idaho Power" or "the Company"). The overall rate of return applied to Idaho Power's 2008 test year rate base is developed in the testimony of Mr. Steve Keen.

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

A. As is common and generally accepted in my field of expertise, I have accessed and used information from a variety of sources. I am familiar with the organization, operations, finances, and operation of Idaho Power from my participation in prior proceedings before the IPUC, the Oregon Public Utility Commission, and the FERC. In connection with the present filing, I considered and relied upon corporate disclosures and management discussions, publicly available financial reports and filings, and other published information relating to the Company and its parent, IDACORP, Inc. ("IDACORP"). I also reviewed information relating generally to current capital market conditions and specifically to current investor perceptions, requirements, and expectations for Idaho Power's electric utility operations. These sources, coupled with my experience in the fields of finance and utility regulation, have given me a working knowledge of investors' ROE requirements for 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 ROE serves to compensate investors for the use of their capital to finance the plant and equipment necessary to provide utility service. Investors commit capital only if they expect to earn a return on their investment commensurate with returns available from alternative investments with comparable risks. To be consistent with sound regulatory economics and the standards set forth by the Supreme Court in the *Bluefield*[1] and *Hope*[2] cases, a utility's allowed ROE should be sufficient to: 1) fairly compensate the utility's investors, 2) enable the utility to offer a return adequate to attract new capital on reasonable terms, and 3) maintain the utility's financial integrity.

Q. How did you go about developing your conclusions regarding a fair rate of return for Idaho Power?

A. I first reviewed the operations and finances of Idaho Power and the general conditions in the utility industry and the economy. With this as a background, I conducted various well-accepted quantitative analyses to estimate the current cost of equity, including alternative applications of the discounted cash flow ("DCF") model and

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[1] Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n, 262 U.S. 679 (1923).

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

the Capital Asset Pricing Model ("CAPM"), as well as reference to comparable earned rates of return expected for utilities. Based on the cost of equity estimates indicated by my analyses, the Company's ROE was evaluated taking into account the specific risks and economic requirements for Idaho Power consistent with preservation of its financial integrity.

B. Summary of Conclusions

Q. What are your findings regarding the fair rate of return on equity for Idaho Power?

A. Based on the results of my analyses and the economic requirements necessary to support continuous access to capital, I recommend that Idaho Power be authorized a fair rate of return on equity in the 10.8 percent to 11.8 percent range. The bases for my conclusion are summarized below:

- In order to reflect the risks and prospects associated with Idaho Power's jurisdictional utility operations, my analyses focused on a proxy group of twenty-seven electric utilities with comparable investment risks. Consistent with the fact that utilities must compete for capital with firms outside their own industry, I also referenced a proxy group of comparable risk companies in the non-utility sector of the economy;
- I applied both the DCF and CAPM methods, as well as the comparable earnings approach, to estimate a fair ROE for Idaho Power:
    - o My application of the constant growth DCF model considered three alternative growth measures based on projected earnings growth, as well as the sustainable, "br+sv" growth rate for each firm in the respective proxy groups;

- After eliminating low- and high-end outliers, my DCF analyses implied a cost of equity of 11.0 percent for the proxy group of electric utilities and 12.6 percent for the group of non-utility companies;
- Application of the CAPM approach using forward-looking data that best reflects the underlying assumptions of this approach implied a cost of equity of 12.3 percent for the electric utilities and 11.5 percent for the non-utility companies;
- Applying the CAPM method using historical realized rates of return resulted in a cost of equity of 10.8 percent for the proxy group of utilities and 10.2 percent for the firms in the non-utility proxy group;
- My evaluation of comparable earned rates of return expected for utilities suggested a cost of equity on the order of at least 11.1 percent for the proxy group of electric utilities;
- Considering these results, and conservatively giving less weight to the upper end of the range, I concluded that the cost of equity for the proxy groups of electric utilities and non-utility companies is on the order of 10.8 percent to 11.8 percent;
- Considering investors' expectations for capital markets and the need to support financial integrity and fund crucial capital investment even under adverse circumstances, it is my opinion that this 10.8 percent to 11.8 percent range bounds a reasonable rate of return on common equity for Idaho Power; and,
- While this "bare-bones" cost of equity range does not consider issuance costs, a flotation cost adder is properly considered in establishing an allowed ROE for Idaho Power from within this range.

Q. What is your conclusion as to the reasonableness of the Company's capital structure?

A. Based on my evaluation, I concluded that a common equity ratio of approximately 49 percent represents a reasonable basis from which to calculate Idaho Power's overall rate of return. This conclusion was based on the following findings:

- Idaho Power's proposed common equity ratio is entirely consistent with range of capitalizations maintained by the firms in the proxy group of electric utilities at year-end 2007 and based on investors' expectations;

- My conclusion is reinforced by the investment community's focus on the need for a greater equity cushion to accommodate higher operating risks, including the uncertainties posed by exposure to variable hydro conditions, and the pressures of capital investments. Financial flexibility plays a crucial role in ensuring the wherewithal to meet the needs of customers, and Idaho Power's capital structure reflects the Company's ongoing efforts to support its credit standing and maintain access to capital on reasonable terms.

Q. What other evidence did you consider in evaluating your recommendation in this case?

A. My recommendation was reinforced by the following findings:

- Sensitivity to regulatory uncertainties has increased dramatically and investors recognize that constructive regulation is a key ingredient in supporting utility credit standing and financial integrity;

- Because of Idaho Power's reliance on hydroelectric generation, the Company is exposed to relatively greater risks of power cost volatility;

- Investors recognize that Idaho Power's Power Cost Adjustment Mechanism ("PCA") provides some level of support for the Company's financial integrity, but they understand that the PCA does not apply to 100 percent of power costs; nor does it insulate Idaho Power from the need to finance accrued power production and supply costs or shield the Company from potential regulatory disallowances.

- Idaho Power must compete for investors' capital with other utilities and businesses of comparable risk. If Idaho Power is not provided an opportunity to earn a return that is sufficient to compensate for the underlying risks, investors will be unwilling to supply capital;

- Providing Idaho Power with the opportunity to earn a return that reflects these realities is an essential ingredient to support the Company's financial position, which ultimately benefits customers by ensuring reliable service at lower long-run costs;
- Past challenges confronting the utility industry illustrate the need to ensure that Idaho Power has the ability to respond effectively to unforeseen events.

Ultimately, it is customers and the service area economy that enjoy the rewards that come from ensuring that the utility has the financial wherewithal to take whatever actions are necessary to provide a reliable energy supply.

II. FUNDAMENTAL ANALYSES

Q. What is the purpose of this section?

A. As a predicate to my economic and capital market analyses, this section examines conditions in the utility industry generally, and for Idaho Power specifically, that investors consider in evaluating their required rate of return. An understanding of these fundamental factors, which drive the risks and prospects for Idaho Power, is essential to develop an informed opinion about investor expectations and requirements that form the basis of a fair rate of return on equity.

A. <u>Idaho Power Company</u>

Q. Briefly describe Idaho Power.

A. Idaho Power is a wholly-owned subsidiary of IDACORP, Inc. ("IDACORP") and is principally engaged in providing integrated retail electric utility service in a 24,000 square mile area in southern Idaho and eastern Oregon. During 2007, Idaho Power's energy deliveries totaled 17.3 million megawatt hours ("MWh"). Sales to residential customers comprised 36 percent of retail sales, with 27 percent to commercial, 24 percent to industrial end-users, and 13 percent attributable to irrigation pumping. Idaho Power also supplies firm wholesale power service to various utilities and large customers under sales contracts. IPC's service territory experienced record-setting high temperatures during 2007 and due to these weather conditions and continued customer growth, IPC set three new all-time system peaks. At year-end 2007, Idaho Power had total assets of $3.5 billion, with total revenues amounting to approximately $875 million.

In addition to its thermal baseload and peaking units located in Wyoming, Nevada and Idaho, Idaho Power's existing generating units include 17 hydroelectric generating plants located in southern Idaho and eastern Oregon. The electrical output of these hydro plants, which has a significant impact on total energy costs, is dependent on streamflows. Although Idaho Power estimates that hydroelectric generation is capable of supplying approximately 55 percent of total system requirements under normal conditions, the Company has experienced prolonged periods of persistent below-normal water conditions in the past.

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 most utilities. While hydropower confers advantages in terms of fuel cost savings and diversity, reduced hydroelectric generation due to below-average water conditions forces Idaho Power to rely more heavily on wholesale power markets or more costly thermal generating capacity to meet its resource needs. As Standard & Poor's Corporation ("S&P") recently observed:

> A reduction in hydro generation typically increases an electric utility's costs by requiring it to buy replacement power or run more expensive generation to serve customer loads. Low hydro generation can also reduce utilities' opportunity to make off-system sales. At the same time, low hydro years increase regional wholesale power prices, creating potentially a double impact - companies have to buy more power than under normal conditions, paying higher prices.[3]

Investors recognize that uncertainties over water conditions are a persistent operational risk associated with Idaho

[3] Standard & Poor's Corporation, "Pacific Northwest Hydrology And Its Impact On Investor-Owned Utilities' Credit Quality," *RatingsDirect* (Jan. 28, 2008).

Power. In addition to weather-related fluctuations in water flows, Idaho Power is also exposed to uncertainties regarding water rights and the administration of those rights.

Idaho Power's retail electric operations are subject to the jurisdiction of the IPUC and the Oregon Public Utility Commission, with the interstate jurisdiction regulated 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. 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 ("Hells Canyon"), which represents 68 percent of the Company's hydro capacity and 40 percent of its total generating capability.

In June 2003, after a prolonged period of planning and consultation with interested parties, Idaho Power submitted a license application for Hells Canyon that included various protection, mitigation, and enhancement measures in order to address environmental concerns while preserving the peak and load following operations of the facilities. The current license for Hells Canyon expired at the end of July 2005 and until the new multi-year license is issued, Idaho Power will operate the project under an annual license issued by FERC. Apart from significant ongoing expenditures associated with proposed environmental measures, the relicensing process is complex, protracted, and expensive. As of December 31, 2007, Idaho Power had accumulated $96 million of construction work in progress associated with its Hells Canyon relicensing efforts.

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 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, rates are reduced when increased hydroelectric generation leads to lower power supply costs. 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.

Q. Are there other mechanisms that affect Idaho Power's rates for utility service?

A. Yes. Included in the provisions of Idaho Power's PCA is a Load Growth Adjustment Rate ("LGAR"). The LGAR subtracts the cost of serving new Idaho retail customers from the power supply costs that the Company is allowed to include in its PCA. The IPUC has recognized that Idaho Power would nevertheless continue to be exposed to the risks of shortfalls associated with load growth. The IPUC specifically noted that these uncertainties are properly considered in establishing a fair ROE for Idaho Power:

> Because this process puts the Company at some business and financial risk, it is awarded a commensurate equity return. Idaho Power's current equity return was set in a process that recognized it would not recover the power supply costs of load growth in the PCA mechanism.[4]

In 2007 the IPUC also approved a Fixed Cost Adjustment Mechanism ("FCA") for Idaho Power under a three-year pilot program applicable to residential and small commercial customer classes. The FCA adjusts rates upward or downward to insulate the recovery of fixed costs from the volume of Idaho Power's energy sales. The pilot program includes various provisions related to customer count and weather normalization methodology, reporting requirements, and detailed disclosure of demand-side management activities.

Q. What credit ratings have been assigned to Idaho Power?

A. Citing concerns over deteriorating financial metrics and the outcome of Idaho Power's last rate proceeding before the IPUC, S&P lowered Idaho Power's

[4] Order No. 30215 at 10.

corporate credit rating from "BBB+" to "BBB" in January 2008.[5] While Moody's Investors Service ("Moody's) has so far maintained the Company's issuer rating at "Baa1", it recently revised its outlook for Idaho Power to "negative" based on similar concerns, warning investors of the potential for a downgrade in the Company's credit standing going forward.[6] Fitch Ratings Ltd. ("Fitch") has assigned the Company an issuer default rating of "BBB" and, like Moody's, has revised Idaho Power's Ratings Outlook to "negative."[7]

Q. Does Idaho Power anticipate the need to access the capital markets going forward?

A. Most definitely. Idaho Power will require capital investment to meet customer growth, provide for necessary maintenance and replacements of its utility infrastructure, as well as fund new investment in electric generation, transmission and distribution facilities. Idaho Power's service area has experienced strong population growth, and the Company's most recent resource plan anticipates the addition of 11,000 to 12,000 new customers annually.[8] In

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[5] Standard & Poor's Corporation, "IDACORP, Idaho Power Co. Ratings Lowered One Notch To 'BBB'; Outlook Stable," *RatingsDirect* (Jan. 31, 2008).

[6] Moody's Investors Service, "Moody's Changes Outlook Of Idacorp And Sub To Negative," *Press Release* (June 3, 2008).

[7] Fitch Ratings Ltd., "Idaho Power Company," *Global Power U.S. and Canada Credit Analysis* (Apr. 10, 2008).

[8] Idaho Power Company, *2006 Integrated Resource Plan* (Oct. 12, 2006) at 1.

order to keep pace with customer growth, enhance transmission infrastructure, and balance generation resource uncertainty Idaho Power anticipates construction expenditures of approximately $900 million over the period 2008-2010.[9]

Over the ten-year planning period, Idaho Power's Integrated Resource Plan has identified the potential need for the Company to obtain 1,063 MW of supply-side capacity, which will entail additional purchased power commitments and financing construction of additional baseload generation, in addition to other system upgrades.[10] Moreover, as indicated earlier, Idaho Power must also bear the costs of protection, mitigation, and enhancement measures associated with Hells Canyon relicensing. Considering the unfavorable outlook for the Company's credit standing, support for Idaho Power's financial integrity and flexibility will be instrumental in attracting the capital necessary to fund these projects in an effective manner.

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[9] IDACORP, Inc., *2007 Form-10K Report* at 27. This amount excludes expenditures for a 250-MW combined cycle combustion turbine expected to be operational in mid-2012 as well as any estimated costs attributable to the Gateway West Project, which contemplates construction of two 500-kV transmission lines with an estimated cost to Idaho Power of between $800 million and $1.2 billion.

[10] Idaho Power Company, *2006 Integrated Resource Plan* (Oct. 12, 2006) at 95.

B. Utility Industry

Q. How have investors' risk perceptions for firms involved in the utility industry evolved?

A. Since the 1990s, the industry has experienced significant structural change resulting from market forces and legislative and regulatory initiatives. Implementation of structural change and related events caused investors to rethink their assessment of the relative risks associated with the utility industry. The past decade witnessed steady erosion in credit quality throughout the utility industry, both as a result of revised perceptions of the risks in the industry and the weakened finances of the utilities themselves. S&P recently reported that the majority of the companies in the utility sector now fall in the triple-B rating category,[11] with Fitch recently concluding that "the long-term outlook is negative" for investor-owned electric utilities.[12] Similarly, Moody's observed, "Material negative bias appears to be developing over the intermediate and longer term due to rapidly rising business and operating risks."[13]

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[11] Standard & Poor's Corporation, "U.S. Electric utility Sector Continues To Benefit From Strong Liquidity Amid Current Credit Crunch," *RatingsDirect* (Mar. 27, 2008).

[12] Fitch Ratings, Ltd., "U.S. Utilities, Power and Gas 2008 Outlook," *Global Power North America Special Report* (Dec. 11, 2007).

[13] Moody's Investors Service, "U.S. Electric Utility Sector," *Industry Outlook* (Jan. 2008).

Q. What other key factors are of concern to investors?

A. In recent years, utilities and their customers have also had to contend with dramatic fluctuations in energy costs due to ongoing price volatility in the spot markets. Investors recognize that the prospect of further turmoil in energy markets is an ongoing concern. S&P has reported continued spikes in wholesale energy market prices,[14] with Moody's warning investors of ongoing exposure to "extremely volatile" energy commodity costs, including purchased power prices, which are heavily influenced by fuel costs.[15] Similarly, the FERC Staff has continued to recognize the ongoing potential for market disruption. A 2008 market assessment report recognized ongoing concerns regarding tight supply and congestion and observed that wholesale power prices across the nation are likely to be significantly higher than the previous year.[16] FERC continues to warn of load pockets vulnerable to periods of high peak demand and unplanned outages of generation or transmission capacity and ongoing reliability concerns that

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[14] Standard & Poor's Corporation, "Fuel and Purchased Power Cost Recovery in the Wake of Volatile Gas and Power Markets - U.S. Electric Utilities to Watch" *RatingsDirect* (Mar. 22, 2006).

[15] Moody's Investors Service, "Storm Clouds Gathering on the Horizon for the North American Electric Utility Sector," *Special Comment* at 6 (Aug. 2007).

[16] FERC, Office of Market Oversight and Investigations, "2008 Summer Market and Reliability Assessment," (May 15, 2008).

led FERC to establish mandatory standards for the bulk power system.[17]

Additionally, in recent years, utilities and their customers have also had to contend with dramatic fluctuations in natural gas costs due to ongoing price volatility in the spot markets.[18] S&P observed that "natural gas prices have proven to be very volatile," warning of a "turbulent journey" due to the uncertainty associated with future fluctuations in energy costs,[19] and concluding: "Cost pressures from natural gas are not likely to recede in the near future."[20] Fitch also highlighted the challenges that fluctuations in commodity prices can have for utilities and their investors, concluding that gas prices are subject to near-term and longer-term fluctuations that contribute to an "adverse environment" for electric utilities.[21]

In addition, while coal-fired generation has historically provided relative stability with respect to

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

[18] For example, the Department of Energy's Energy Information Administration ("EIA") reported that the average price of gas used by electricity generators (regulated utilities and non-regulated power producers) spiked from an average price of $7.18 per Mcf for the first eight months of 2005 to over $11.00 per Mcf in September and October 2005 (http://tonto.eia.doe.gov/dnav/ng/hist/n3045us3m.htm).

[19] Standard & Poor's Corporation, "Top Ten Credit Issues Facing U.S. Utilities," *RatingsDirect* (Jan. 29, 2007).

[20] *Id.*

[21] Fitch Ratings, Ltd., "U.S. Power and Gas 2008 Outlook," *Global Power North American Special Report*, at 3 (Dec. 11, 2007).

fuel costs, higher prices have raised investors' concerns. In a 2004 article entitled "Rising Coal Prices May Threaten U.S. Utility Credit Profiles," S&P noted that:

> More recently, several current and structural developments for the coal mining industry have resulted in a dramatic increase in spot coal prices.[22]

The EIA reported that average delivered coal prices for electric utilities increased 9.7 percent in 2006, the sixth consecutive annual rise,[23] while Reuters Inc. reported in May 2008 that benchmark coal prices exceeded $100 per ton, or over twice the levels of the previous fall.[24]

Q. What are the key uncertainties considered by investors in assessing their required rate of return for Idaho Power?

A. Because roughly 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 most utilities. While hydropower confers advantages in terms of fuel cost savings and diversity, reduced hydroelectric generation due to below-average water conditions forces Idaho Power to rely more heavily on

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[22] Standard & Poor's Corporation, "Rising Coal Prices May Threaten U.S. Utility Credit Profiles," *RatingsDirect* (Aug. 12, 2004).

[23] Energy Information Administration, *Annual Coal Report 2006* at 9 (Nov. 2007).

[24] Nichols, Bruce, "US coal prices pass $100 a ton, twice last fall's," *Reuters* (May 9, 2008).

purchased power or more costly thermal generating capacity to meet its resource needs.

The prolonged drought conditions experienced in the recent past have only deepened concerns over power prices and fluctuations in gas costs. As S&P noted, "hydro resources expose the company to substantial replacement power price risk in the event of low water flows."[25] S&P concluded that Idaho Power "has the greatest hydro exposure" of any utility and faces "the most substantial risks."[26] Investors recognize the significant financial burden that constrained hydro generation imposes on Idaho Power, as Moody's summarized:

> The company's recent financial metrics, including its coverage of interest and debt by cash flow from operations exclusive of working capital changes (CFO Pre-W/C), have been pressured to a level we often see for a regulated electric utility in the Ba rating category. These recent metrics are the result of unfavorable hydro conditions and the adverse effects the recent increase to the load growth adjustment rate (LGAR) has had on net power supply cost recovery under the power cost adjustment (PCA) mechanism.[27]

Similarly, Fitch concluded that its negative outlook on Idaho Power's ratings "primarily reflect persistent drought

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[25] Standard & Poor's Corporation, "IDACORP, Idaho Power Co. Ratings Lowered One Notch To 'BBB'; Outlook Stable," *RatingsDirect* (Jan. 31, 2008).

[26] Standard & Poor's Corporation, "Pacific Northwest Hydrology And Its Impact On Investor-Owned Utilities' Credit Quality," *RatingsDirect* (Jan. 28, 2008).

[27] Moody's Investors Service, "Credit Opinion: Idaho Power Company," *Global Credit Research* (June 4, 2008).

conditions in recent years and their adverse impact on the utility's cash flows, earnings and credit metrics."[28]

Volatile energy markets, unpredictable stream flows, and Idaho Power's reliance on wholesale purchases to meet a portion of its resource needs expose the Company to the risk of reduced cash flows and unrecovered power supply costs. The IPUC has recognized "the unique circumstances of Idaho Power's highly variable power supply costs."[29] The Company's reliance on purchased power to meet shortfalls in hydroelectric generation magnifies the importance of strengthening financial flexibility to ensure access to the cash resources and interim financing required to meet any shortfall in operating cash flows, as well as fund required investments in the utility system.

Q. Does the PCA remove the risk associated with fluctuations in power supply costs?

A. No. While the PCA provides some level of support for the Company's financial integrity, it does not apply to 100 percent of power costs. Moreover, even for utilities with permanent energy cost 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. This lag can impinge on the utility's

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[28] Fitch Ratings, Ltd., "Idaho Power Company," *Global Power U.S. and Canada Credit Analysis* (Apr. 10, 2008).
[29] Order No. 30215 at 9.

financial strength through reduced liquidity and higher borrowings. As S&P observed:

> Because increased purchases and higher prices are not immediately met by increased retail revenues from customers, cash flows can decline in low water years. While PCAs and annual power cost updates can mitigate these effects, they are not designed to completely insulate a utility from poor hydro conditions. As a result, a large annual deviation from normal streamflow typically weakens cash coverage of debt and interest for a utility.[30]

S&P recently cited exposure to high deferred power costs resulting from "extremely variable" hydro generation as a key challenge facing Idaho Power.[31] Similarly, Moody's observed that the Company's financial metrics "are pressured relative to the current Baa1 rating and we expect that the company's financial performance will remain subject to the vagaries of water flow conditions."[32] Moreover, even with an energy cost adjustment mechanism, investors continue to recognize the ongoing potential for regulatory disallowances if the IPUC determines that the amounts were not prudently incurred.

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[30] Standard & Poor's Corporation, "Pacific Northwest Hydrology And Its Impact On Investor-Owned Utilities' Credit Quality," *RatingsDirect* (Jan. 28, 2008).

[31] Standard & Poor's Corporation, "Idaho Power Co.," *RatingsDirect* (Feb. 1, 2008).

[32] Moody's Investors Service, "Credit Opinion: Idaho Power Company," *Global Credit Research* (June 4, 2008).

Q. What other considerations affect investors' evaluation of Idaho Power?

A. Investors are aware of the financial and regulatory pressures faced by utilities associated with rising costs and the need to undertake significant capital investments. As Moody's observed:

> [T]here are concerns arising from the sector's sizeable infrastructure investment plans in the face of an environment of steadily rising operating costs. Combined, these costs and investments can create a continuous need for regulatory rate relief, which in turn can increase the likelihood for political and/or regulatory intervention.[33]

Similarly, S&P noted that "onerous construction programs", along with rising operating and maintenance costs and volatile fuel costs, were a significant challenge to the utility industry.[34] Moody's recently echoed this assessment, concluding, "There are significant negative trends developing over the longer-term horizon."[35]

While providing the infrastructure necessary to meet the energy needs of customers is certainly desirable, it imposes additional financial responsibilities on Idaho Power. As noted earlier, the Company's plans include

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[33] Moody's Investors Service, "Storm Clouds Gathering on the Horizon for the North American Electric Utility Sector," *Special Comment* (Aug. 2007).

[34] Standard & Poor's Corporation, "U.S. Electric Utilities Continued Their Long Shift To Stability In Third Quarter," *RatingsDirect* (Oct. 23, 2007).

[35] Moody's Investors Service, "U.S. Utility Sector," *Industry Outlook* (Jan. 2008).

substantial capital expenditures, including enhancements to its transmission and distribution system and investment in generating resources. Investors are aware that the challenge of achieving timely regulatory recovery associated with rising costs and burdensome capital expenditure requirements impacts the Company's ability to earn a fair rate of return. For example, S&P cited "[r]egulatory challenges in meeting rising costs and a large capital expenditure program, resulting from high customer growth," as a key weakness for Idaho Power,[36] while Fitch noted that the inability to increase base rates to recover anticipated capital investment could lead to a downgrade in the Company's credit standing.[37]

In addition, electric utilities are confronting increased environmental pressures that are imposing significant uncertainties and costs. Utilities required to meet renewable portfolio standards and carbon reduction goals generally must embrace energy efficiency and conservation initiatives that lead to decreased demand and revenue erosion. In early 2007, S&P cited environmental mandates, including emissions, conservation, and renewable resources, as one of the top ten credit issues facing U.S.

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[36] Standard & Poor's Corporation, "Idaho Power Co.," *RatingsDirect* (Feb. 1, 2008).

[37] Fitch Ratings, Ltd., "Idaho Power Company," *Global Power U.S. and Canada Credit Analysis* (Apr. 10, 2008).

utilities.[38] More recently, S&P cited the long-term challenge posed by climate change legislation and observed that:

> What the ultimate outcome will be is cloudy right now, but legislation addressing carbon emissions and other greenhouse gases is extremely probable in the near future. The credit implications of any policy will be vast due to the compliance costs involved.[39]

Similarly, Moody's noted that "increasingly stringent environmental compliance mandates will elevate cash outflow recovery risk",[40] while Fitch noted that the electric utility industry would be "a primary target" of new environmental legislation, and concluded: "The murkiness of the future policies and regulations on carbon emissions is another factor clouding Fitch's long-term view of electric utilities."[41] Compliance with these evolving standards almost certainty will mean significant capital expenditures.

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[38] Standard & Poor's Corporation, "Top Ten Credit Issues Facing U.S. Utilities," *RatingsDirect* (Jan. 29, 2007).

[39] Standard & Poor's Corporation, "Upgrades Lead In U.S. Electric Utility Industry In 2007," *RatingsDirect* (Jan. 17, 2008).

[40] Moody's Investors Service, "U.S. Electric Utility Sector," *Industry Outlook* (Jan. 2008).

[41] Fitch Ratings, Ltd., "U.S. Utilities, Power and Gas 2008 Outlook," *Global Power North America Special Report* (Dec. 11, 2007).

Q. Have investors recognized that electric utilities face additional risks because of the impact of industry restructuring on transmission operations?

A. Yes. Policy evolution in the transmission area has been wide reaching and Idaho Power must address changes in the electric transmission function of its business. S&P confirmed a "continued lack of clarity from lawmakers and regulators on the regulatory framework surrounding transmission projects."[42] Transmission operations have become increasingly complex and investors have recognized that difficulties in obtaining permits and uncertainty over the adequacy of allowed rates of return have contributed to heightened risk and fueled concerns regarding the need for additional investment in the transmission sector of the electric power industry.

III. CAPITAL MARKET ESTIMATES

Q. What is the purpose of this section?

A. This section presents capital market estimates of the cost of equity. First, I examine the concept of the cost of equity, along with the risk-return tradeoff principle fundamental to capital markets. Next, I describe DCF and CAPM analyses conducted to estimate the cost of equity for benchmark groups of comparable risk firms and

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[42] Standard & Poor's Corporation, "Capital Spending On Electric Transmission Is On The Upswing Around The World," *RatingsDirect* (Aug. 7, 2006).

evaluate comparable earned rates of return expected for utilities. Finally, I examine other factors (*e.g.*, flotation costs) that are properly considered in evaluating a fair rate of return on equity.

A. Overview

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

A. The return on common equity is the cost of inducing and retaining investment in the utility's physical plant and assets. This investment is necessary to finance the asset base needed to provide utility service. Investors 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. Meeting these objectives allows the utility to fulfill its obligation to provide reliable service while meeting the needs of customers through necessary system expansion.

Q. What fundamental economic principle underlies any evaluation of investors' required return on equity?

A. The fundamental economic principle underlying the cost of equity concept is the notion that investors are risk averse. In capital markets where relatively risk-free assets are available (*e.g.*, U.S. Treasury securities), investors can be induced to hold riskier assets only if they are offered a premium, or additional return, above the rate of return on a risk-free asset. Because all assets compete with each other for investor funds, riskier assets must yield a higher expected rate of return than safer assets to induce investors to invest and 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. Is there evidence that the risk-return tradeoff principle actually operates in the capital markets?

A. Yes. The risk-return tradeoff can be readily documented in segments of the capital markets where required rates of return can be directly inferred from market data and where 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. Yet there is every reason to believe that investors exhibit risk aversion in deciding whether or not to hold common stocks and other assets, just as when choosing among fixed-income securities.

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

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

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

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

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

A. No. I used both the DCF and CAPM methods to estimate the cost of equity, as well as referencing comparable earned rates of return expected for utilities. In my opinion, comparing estimates produced by one method with those produced by other approaches ensures that estimates of the cost of equity pass fundamental tests of reasonableness and economic logic. In addition, I applied the DCF and CAPM to alternative proxy groups of comparable risk firms.

Q. Are you aware that the IPUC has traditionally relied primarily on the DCF and comparable earnings methods?

A. Yes, although the Commission has also evidenced a willingness to weigh alternatives in evaluating an allowed ROE. For example, while noting that it had not focused on the CAPM for determining the cost of equity, the IPUC recognized in Order No. 29505 that "methods to evaluate a common equity rate of return are imperfect predictors" and emphasized "that by evaluating all the methods presented in this case and using each as a check on the other," the Commission had avoided the pitfalls associated with reliance on a single method.[43]

B. Discounted Cash Flow Analyses

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

A. DCF models 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 expectations, 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 implicitly used in bidding the stock to that price.

[43] Order No. 29505 at 38 (emphasis added).

Q. What market valuation process underlies DCF models?

A. DCF models assume 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. Thus, the cost of equity is the discount rate that equates the current price of a share of stock with the present value of all expected cash flows from the stock. 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.

Q. What form of the DCF model is customarily used to estimate the cost of equity in rate cases?

A. Rather than developing annual estimates of cash flows into perpetuity, the DCF model can be simplified to a "constant growth" form:[44]

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

where: P_0 = Current price per share;
D_1 = Expected dividend per share in coming year;
k_e = Cost of equity;
g = Investors' long-term growth expectations.

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

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

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

[44] The constant growth DCF model is dependent on a number of strict assumptions, which in practice are never strictly met. 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.

Q. How did you define the utility proxy group you used to implement the DCF model?

A. In estimating the cost of equity, the DCF model is typically applied to publicly traded firms engaged in similar business activities. In order to reflect the risks and prospects associated with Idaho Power's electric utility operations, my utility proxy group was composed of those dividend-paying companies included by The Value Line Investment Survey ("Value Line") in its Electric Utilities Industry groups with: (1) S&P corporate credit ratings between "BBB-" and "BBB+", (2) a Value Line Safety Rank of "2" or "3", and (3) a Value Line Financial Strength Rating of "B" to "B++". I excluded three firms that otherwise would have been in the proxy group, but are not appropriate for inclusion because they either do not pay common dividends (El Paso Electric Company) or are in the process of being acquired (Energy East Corporation and Puget Energy, Inc.). These criteria resulted in a proxy group composed of 27 comparable risk utilities. I refer to this group as the "Utility Proxy Group."

Q. Do these criteria provide objective evidence that investors would view the firms in your Utility Proxy Group as risk-comparable?

A. Yes. Credit ratings are assigned by independent rating agencies for the purpose of providing investors with a broad assessment of the creditworthiness of a firm.

Because the rating agencies' evaluation includes virtually all of the factors normally considered important in assessing a firm's relative credit standing, corporate credit ratings provide a broad measure of overall investment risk that is readily available to investors. Widely cited in the investment community and referenced by investors as an objective measure of risk, credit ratings are also frequently used as a primary risk indicator in establishing proxy groups to estimate the cost of equity.

While credit ratings provide the most widely referenced benchmark for investment risks, other quality rankings published by investment advisory services also provide relative assessments of risk that are considered by investors in forming their expectations. Value Line's primary risk indicator is its Safety Rank, which ranges from "1" (Safest) to "5" (Riskiest). This overall risk measure is intended to capture the total risk of a stock, and incorporates elements of stock price stability and financial strength. Given that Value Line is perhaps the most widely available source of investment advisory information, its Safety Rank provides a useful guide to the likely risk perceptions of investors.

The Financial Strength Rating is designed as a guide to overall financial strength and creditworthiness, with the key inputs including financial leverage, business volatility measures, and company size. Value Line's Financial Strength

Ratings range from "A++" (strongest) down to "C" (weakest) in nine steps.

As discussed earlier, Idaho Power is rated "BBB" by S&P, which is identical to the average for the firms in the Utility Proxy Group. Meanwhile, Value Line has assigned IDACORP a Safety Rank of "3" and a Financial Strength Rating of "B+".[45] Based on these criteria, which reflect objective, published indicators that incorporate consideration of a broad spectrum of risks, including financial and business position, relative size, and exposure to company specific factors, investors are likely to regard this group as having comparable risks and prospects.

Q. What steps are required to apply the DCF model?

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. 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.

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[45] As noted earlier, Idaho Power is a wholly-owned subsidiary of IDACORP. Because Value Line's risk indicators apply to publicly traded common stock, I referenced published values for IDACORP in selecting a risk-comparable proxy group.

Q. How was the dividend yield for the Utility Proxy Group determined?

A. Estimates of dividends to be paid by each of these 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 prices, and resulting dividend yields for the firms in the Utility Proxy Group are presented on Exhibit No. 17. As shown there, dividend yields for the firms in the Utility Proxy Group ranged from 1.2 percent to 6.1 percent.

Q. What is the next step in applying the constant growth DCF model?

A. The next step is to evaluate long-term growth expectations, or "*g*", for the firm in question. 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. A wide variety of techniques can be used to derive growth rates, but the only "*g*" that matters in applying the DCF model is the value that investors expect.

Q. Are historical growth rates likely to be representative of investors' expectations for utilities?

A. No. If past trends in earnings, dividends, and book value are to be representative of investors' expectations for the future, then the historical conditions giving rise to these growth rates should be expected to continue. That is clearly not the case for utilities, where structural and industry changes have led to declining dividends, earnings pressure, and, in many cases, significant write-offs. While these conditions serve to depress historical growth measures, they are not representative of long-term expectations for the utility industry. Moreover, to the extent historical trends for utilities are meaningful, they are also captured in projected growth rates, since securities analysts also routinely examine and assess the impact and continued relevance (if any) of historical trends.

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

A. While the DCF model is technically concerned with growth in dividend cash flows, implementation of this DCF model is solely concerned with replicating the forward-looking evaluation of real-world investors. In the case of utilities, dividend growth rates are not likely to provide a meaningful guide to investors' current growth expectations. This is because utilities have significantly altered their dividend policies in response to more accentuated business risks in the industry.[46] As a result of this trend towards a more conservative payout ratio, dividend growth in the utility industry has remained largely stagnant as utilities conserve financial resources to provide a hedge against heightened uncertainties.

As payout ratios for firms in the utility industry trended downward, investors' focus has increasingly shifted from dividends to earnings as a measure of long-term growth. Future trends in earnings, which provide the source for future dividends and ultimately support share prices, play a pivotal role in determining investors' long-term growth expectations. 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 future performance.[47]

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[46] For example, the payout ratio for electric utilities fell from approximately 80 percent historically to on the order of 60 percent. The Value Line Investment Survey (Sep. 15, 1995 at 161, Dec. 28, 2007 at 695).

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

Value Line's near-term projections and its Timeliness Rank,[48] 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%.[49]

The fact that investment advisory services focus on growth in earnings indicates that the investment community regards this as a superior indicator of future long-term growth. Indeed, "A Study of Financial Analysts: Practice and Theory," published in the *Financial Analysts Journal*, reported the results of a survey conducted to determine what analytical techniques investment analysts actually use.[50] 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.[51]

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[48] The Timeliness Rank presents Value Line's assessment of relative price performance during the next six to twelve months based on a five point scale.

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

[50] Block, Stanley B., "A Study of Financial Analysts: Practice and Theory", *Financial Analysts Journal* (July/August 1999).

[51] *Id.* at 88.

More recently, the *Financial Analysts Journal* reported the results of a study of the relationship between valuations based on alternative multiples and actual market prices, which concluded, "In all cases studied, earnings dominated operating cash flows and dividends."[52]

Q. What are security analysts currently projecting in the way of growth for the firms in the Utility Proxy Group?

A. The earnings growth projections for each of the firms in the Utility Proxy Group reported by Value Line, Thomson Financial ("Thomson"),[53] and Zacks Investment Research ("Zacks") are displayed on Exhibit No. 17.

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

A. Based on the assumptions underlying constant growth theory, conventional applications of the constant growth DCF model often examine the relationship between retained earnings and earned rates of return as an indication of the sustainable growth investors might expect from the reinvestment of earnings within a firm. The sustainable growth rate is calculated by the following formula:

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[52] Liu, Jing, Nissim, Doron, & Thomas, Jacob, "Is Cash Flow King in Valuations?," *Financial Analysts Journal*, Vol. 63, No. 2 (March/April 2007) at 56.

[53] Thomson Financial, an arm of The Thomson Corporation, compiles and publishes consensus securities analyst growth rates under the IBES and First Call brands.

$$g = br + sv$$

where:
- g = investors' expected long-term growth rate;
- b = expected retention ratio;
- r = expected earned return on equity;
- s = percent of common equity expected to be issued annually as new common stock; and,
- v = expected equity accretion rate.

Q. What is the purpose of the "sv" term?

A. Under DCF theory, the "sv" factor is a component of the growth rate designed to capture the impact of issuing new common stock at a price above, or below, book value. When a company's stock price is greater than its book value per share, the per-share contribution in excess of book value associated with new stock issues will accrue to the current shareholders. This increase to the book value of existing shareholders leads to higher expected earnings and dividends, with the "sv" factor incorporating this additional growth component.

Q. What growth rate does the earnings retention method suggest for the Utility Proxy Group?

A. The sustainable, "br+sv" growth rates for each firm in the Utility Proxy Group are summarized on Exhibit No. 17, with the underlying details being presented on Exhibit No. 18. 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. Because Value Line reports end-of-year book values, an adjustment was incorporated to compute an average rate of return over the year, consistent with the theory underlying this approach to estimating investors' growth expectations. Meanwhile, the percent of common equity expected to be issued annually as new common stock (s) was equal to the product of the projected market-to-book ratio and growth in common shares outstanding, while the equity accretion rate (v) was computed as 1 minus the inverse of the projected market-to-book ratio.

Q. What cost of equity estimates were implied for the Utility Proxy Group using the DCF model?

A. After combining the dividend yields and respective growth projections for each utility, the resulting cost of equity estimates are shown on Exhibit No. 17.

Q. In evaluating the results of the constant growth DCF model, is it appropriate to eliminate cost of equity estimates that fail to meet threshold tests of economic logic?

A. Yes. It is a basic economic principle that investors can be induced to hold more risky assets only if they expect to earn a return to compensate them for their risk bearing. As a result, the rate of return that investors require from a utility's common stock, the most junior and highest risk of its securities, must be considerably higher than the yield offered by senior, long-term debt. Consistent with this principle, the DCF range for the Utility Proxy Group must be adjusted to eliminate cost of equity estimates that fail fundamental tests of economic logic.

Q. Have similar tests been applied by regulators?

A. Yes. The FERC has noted that adjustments are justified where applications of the DCF approach produce illogical results. FERC evaluates DCF results against observable yields on long-term public utility debt and has recognized that it is appropriate to eliminate cost of equity estimates that do not sufficiently exceed this threshold. In a 2000 opinion establishing its current precedent for determining ROEs for electric utilities, for example, FERC concluded:

> An adjustment to this data is appropriate in the case of PG&E's low-end return of 8.42%, which is comparable to the average Moody's "A" grade public utility bond yield of 8.06%, for October 1999. Because investors cannot be expected to purchase stock if debt, which has less risk than stock, yields essentially the same return, this low-end return cannot be considered reliable in this case.[54]

Similarly, in its October 2006 decision in *Kern River Gas Transmission Company*, FERC noted that:

> [T]he 7.31 and 7.32% costs of equity for El Paso and Williams found by the ALJ are only 110 and 122

[54] *Southern California Edison Company*, 92 FERC ¶ 61,070 (2000) at p. 22.

basis points above that average yield for public utility debt.[55]

FERC upheld the opinion of Staff and the Administrative Law Judge that cost of equity estimates for these two proxy group companies "were too low to be credible."[56]

Q. What does this test of logic imply with respect to the DCF results for the Utility Proxy Group?

A. The average credit rating associated with the firms in the Utility Proxy group is "BBB". Corporate credit ratings of "BBB-", "BBB", and "BBB+" are all considered part of the triple-B rating category, with Moody's monthly yields on triple-B bonds averaging approximately 6.9 percent in May 2008.[57] As highlighted on Exhibit No. 17, eight of the individual equity estimates for the firms in the Utility Proxy Group fell below 8 percent.[58] In light of the risk-return tradeoff principle, it is inconceivable that investors are not requiring a substantially higher rate of return for holding common stock, which is the riskiest of a utility's securities. As a result, these values provide little guidance as to the returns investors require from the common stock of an electric utility.

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

[56] *Id.*

[57] Moody's Investors Service, *www.CreditTrends.com*.

[58] As highlighted on Exhibit 2, these DCF estimates ranged from 6.2 percent to 7.8 percent.

Q. Do you also recommend excluding cost of equity estimates at the high end of the range of DCF results?

A. Yes. The upper end of the cost of equity range produced by the DCF analysis presented in Exhibit No. 17 was set by a cost of equity estimate of 23.0 percent for Allegheny Energy, with eleven other DCF estimates ranging from 17.1 percent to 22.7 percent. Compared with the balance of the remaining estimates, these results are extreme outliers and should also be excluded in evaluating the results of the DCF model for the Utility Proxy Group. This is also consistent with the threshold adopted by FERC, which established that a 17.7 percent DCF estimate for was "an extreme outlier" and should be disregarded.[59]

Q. What cost of equity is implied by your DCF results for the Utility Proxy Group?

A. As shown on Exhibit No. 17 and summarized in Table 1, below, after eliminating illogical low- and high-end values, application of the constant growth DCF model resulted in the following cost of equity estimates:

TABLE 1
DCF RESULTS – UTILITY PROXY GROUP

Growth Rate	Average Cost of Equity
Value Line	11.7%
IBES	11.6%
Zacks	11.1%
br+sv	9.5%

[59] *ISO New England, Inc.*, 109 FERC ¶ 61,147 at P 205 (2004).

Q. What did you conclude based on the results of the DCF analyses for the Utility Proxy Group?

A. Taken together, and considering the relative strengths and weaknesses associated with the alternative growth measures, I concluded that the constant growth DCF results for the Electric Utility Proxy Group implied a cost of equity of 11.0 percent.

Q. How else can the DCF model be applied to estimate the ROE for Idaho Power?

A. Under the regulatory standards established by *Hope* and *Bluefield*, the salient criteria in establishing a meaningful benchmark to evaluate a fair rate of return is relative risk, not the particular business activity or degree of regulation. Utilities must compete for capital, not just against firms in their own industry, but with other investment opportunities of comparable risk. With regulation taking the place of competitive market forces, required returns for utilities should be in line with those of non-utility firms of comparable risk operating under the constraints of free competition. Consistent with this accepted regulatory standard, I also applied the DCF model to a reference group of comparable risk companies in the non-utility sectors of the economy. I refer to this group as the "Non-Utility Proxy Group".

Q. What criteria did you apply to develop the Non-Utility Proxy Group?

A. To reflect investors' risk perceptions in developing the Non-Utility Proxy Group, my assessment of comparable risk relied on three objective benchmarks for the risks associated with common stocks - Value Line's Safety Rank, Financial Strength Rating, and beta. Given that Value Line is perhaps the most widely available source of investment advisory information, its Safety Rank and Financial Strength Rating provide useful guidance regarding the risk perceptions of investors. These objective, published indicators incorporate consideration of a broad spectrum of risks, including financial and business position, relative size, and exposure to company-specific factors.

My comparable risk proxy group was composed of those U.S. companies followed by Value Line that: 1) pay common dividends; 2) have a Safety Rank of "1"; 3) have a Financial Strength Rating of "A" or above; and 4) have beta values of 0.90 or less.[60] Consistent with the development of my Utility Proxy Group, I also eliminated firms with below-investment grade credit ratings. Table 2 compares the Non-

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[60] This threshold corresponds to the average betas for the Electric Utility Proxy Group of 0.88.

Utility Proxy Group with the Utility Proxy Group and Idaho Power across four key indicators of investment risk:[61]

TABLE 2
COMPARISON OF RISK INDICATORS

	S&P Credit Rating	Value Line Safety Rank	Value Line Financial Strength	Value Line Beta
Non-Utility Group	A+	1	A+	0.79
Utility Proxy Group	BBB	3	B+	0.88
Idaho Power	BBB	3	B+	0.90

Considered along with S&P's corporate credit ratings, a comparison of these Value Line indicators suggests that the investment risks associated with the Non-Utility Proxy Group are below those of the group of utilities and Idaho Power.

Q. What were the results of your DCF analysis for the Non-Utility Proxy Group?

A. As shown on Exhibit No. 19, I applied the DCF model to the Non-Utility Proxy Group in exactly the same manner described earlier for the Utility Proxy Group.[62] As summarized in Table 3, below, after eliminating illogical low- and high-end values, application of the constant growth DCF model resulted in the following cost of equity estimates:

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[61] Because Idaho Power has no publicly traded common stock, the Value Line risk measures shown reflect those published for its parent, IDACORP. As explained earlier, in my opinion these risk measures are indicative of the risk of Idaho Power.

[62] Exhibit 5 contains the details underlying the calculation of the br+sv growth rates for the Non-Utility Proxy Group.

TABLE 3
DCF RESULTS - NON-UTILITY PROXY GROUP

Growth Rate	Average Cost of Equity
Value Line	12.3%
IBES	12.8%
Zacks	12.5%
br+sv	12.7%

Q. What did you conclude based on the results of the DCF analyses for the Non-Utility Proxy Group?

A. Taken together, I concluded that the constant growth DCF results for the Non-Utility Proxy Group implied a cost of equity of 12.6 percent. As discussed earlier, reference to the Non-Utility Proxy Group is consistent with established regulatory principles and required returns for utilities should be in line with those of non-utility firms of comparable risk operating under the constraints of free competition.

Q. Do you believe the DCF model should be relied on exclusively to evaluate a reasonable ROE for the proxy groups or Idaho Power?

A. No. Because the cost of equity is unobservable, no single method should be viewed in isolation. While the DCF model has been routinely relied on in regulatory proceedings as one guide to investors' required return, it is widely recognized that no single method can be regarded as definitive. For example, a publication of the Society of Utility and Financial Analysts (formerly the National Society of Rate of Return Analysts), concluded that:

> Each model requires the exercise of judgment as to the reasonableness of the underlying assumptions of the methodology and on the reasonableness of the proxies used to validate the theory. Each model has its own way of examining investor behavior, its own premises, and its own set of simplifications of reality. Each method proceeds from different fundamental premises, most of which cannot be validated empirically. Investors clearly do not subscribe to any singular method, nor does the stock price reflect the application of any one single method by investors.[63]

Moreover, evidence suggests that reliance on the DCF model as a tool for estimating investors' required rate of return has declined outside the regulatory sphere, with the CAPM being "the dominant model for estimating the cost of equity."[64]

C. Capital Asset Pricing Model

Q. Please describe the CAPM.

A. The CAPM is generally considered to be the most widely referenced method for estimating the cost of equity both among academicians and professional practitioners, with the pioneering researchers of this method receiving the Nobel Prize in 1990. The CAPM is a theory of market equilibrium that measures risk using the beta coefficient. Because investors are assumed to be fully diversified, the

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

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

relevant risk of an individual asset (*e.g.*, common stock) is its volatility relative to the market as a whole, with beta reflecting the tendency of a stock's price to follow changes in the market. The CAPM is mathematically expressed as:

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

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

Like the DCF model, the CAPM is an *ex-ante,* or forward-looking model based on expectations of the future. As a result, in order to produce a meaningful estimate of investors' required rate of return, the CAPM should be applied using estimates that reflect the expectations of actual investors in the market, not with backward-looking, historical data.

Q. How did you apply the CAPM to estimate the cost of equity?

A. Application of the CAPM to the utility proxy group based on a forward-looking estimate for investors' required rate of return from common stocks is presented on Exhibit No. 21. In order to capture the expectations of today's investors in current capital markets, the expected market rate of return was estimated by conducting a DCF analysis on the dividend paying firms in the S&P 500 Composite Index ("S&P 500").

The dividend yield for each firm was obtained from Value Line, with the growth rate being equal to the average of the earnings growth projections for each firm published by IBES and Value Line, with each firm's dividend yield and growth rate being weighted by its proportionate share of total market value. Based on the weighted average of the projections for the 350 individual firms, current estimates imply an average growth rate over the next five years of 10.6 percent. Combining this average growth rate with a dividend yield of 2.4 percent results in a current cost of equity estimate for the market as a whole of approximately 12.9 percent. Subtracting a 4.6 percent risk-free rate based on the average yield on 20-year Treasury bonds for May 2008 produced a market equity risk premium of 8.3 percent. As shown on Exhibit No. 21, multiplying this risk premium by the average Value Line beta of 0.88 for the Utility Proxy Group, and then adding the resulting 7.3 percent risk premium to the average long-term Treasury bond yield, indicated an ROE of approximately 11.9 percent.

Q. What cost of equity was indicated for the Non-Utility Proxy Group based on this forward-looking application of the CAPM?

A. As shown on Exhibit No. 22, applying the forward-looking CAPM approach to the firms in the Non-Utility Proxy Group implied a cost of equity estimate of 11.2 percent.

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

A. In addition, because it is frequently referenced in regulatory proceedings, I also applied the CAPM using risk premiums based on historical realized rates of return published by Ibbotson Associates (now Morningstar). Reference to historical data represents one way to apply the CAPM, but these realized rates of return reflect, at best, an indirect estimate of investors' current requirements. As a result, forward-looking applications of the CAPM that look directly at investors' expectations in the capital markets are apt to provide a more meaningful guide to investors' required rate of return.

Q. What CAPM cost of equity is produced based on historical realized rates of return for stocks and long-term government bonds?

A. Application of the CAPM to the firms in the utility and non-utility proxy groups using risk premiums based on historical realized rates of return published by Ibbotson Associates is presented on Exhibits Nos. 23 and 24, respectively. As shown there, this historical CAPM approach implied a cost of equity of 10.8 percent for the Utility Proxy Group and 10.2 percent for the firms in the Non-Utility Proxy Group.

D. Comparable Earnings Method

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

A. As I noted earlier, I also evaluated the cost of equity using the comparable earnings method. Reference to rates of return available from alternative investments of comparable risk can provide an important benchmark 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 is consistent with the economic underpinnings for a fair rate of return established by the United States Supreme Court and has been traditionally relied on by the IPUC. Moreover, it 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.

Q. What rates of return on equity are indicated for utilities based on this approach?

A. With respect to expectations for electric utilities generally, Value Line reports that its analysts anticipate an average rate of return on common equity for the electric utility industry of 11.5 percent in 2008 and 2009 and 13.0 percent over its three-to-five year forecast horizon.[65] Meanwhile, Value Line expects that natural gas

[65] The Value Line Investment Survey at 150 (May 30, 2008).

distribution utilities will earn an average rate of return on common equity of 11.5 percent in 2008 and 12.0 percent in 2009, and 12.5 percent over the years 2011-2013.[66]

For the firms in the Utility Proxy Group specifically, the returns on common equity projected by Value Line over its three-to-five year forecast horizon are shown on Exhibit No. 25. Consistent with the rational underlying the development of the br+sv growth rates discussed earlier, these year-end values were converted to average returns using the same adjustment factor developed in Exhibit No. 18. As shown on Exhibit No. 25, after eliminating extreme outliers, Value Line's projections suggested an average ROE of 11.1 percent.

Q. What return on equity is indicated by the results of the comparable earnings approach?

A. Based on the results discussed above, I concluded that the comparable earnings approach implies a fair rate of return on equity of at least 11.1 percent.

E. Summary of Results

Q. Please summarize the results of your quantitative analyses.

A. The cost of equity estimates implied by my quantitative analyses are summarized in Table 4 below:

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[66] The Value Line Investment Survey at 446 (Mar. 14, 2008).

TABLE 4
SUMMARY OF QUANTITATIVE RESULTS

Method	Utility	Non-Utility
DCF	11.0%	12.6%
CAPM		
Forward-Looking	11.9%	11.2%
Historical	10.8%	10.2%
Comparable Earnings	11.1%	

F. Flotation Costs

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, *Regulatory Finance: Utilities' Cost of Capital* 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.[67]

Alternatively, a study of data from Morgan Stanley regarding issuance costs associated with utility common stock issuances suggests an average flotation cost percentage of 3.6 percent.[68] Applying these expense percentages to a representative dividend yield for a utility of 3.9 percent implies a flotation cost adjustment on the order of 14 to 39 basis points.

Q. Has the IPUC Staff previously considered flotation costs in establishing a fair ROE for Idaho Power?

A. Yes. For example, in Case No. IPC-E-07-8, IPUC Staff witness Terri Carlock noted that she had adjusted her DCF analysis to incorporate an allowance for flotation costs.[69] While issuance costs are a legitimate consideration in setting the return on equity for a utility,

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

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

[69] Case No. IPC-E-07-8, *Direct Testimony of Terri Carlock* at 10 (Dec. 10, 2007).

a specific adjustment for flotation costs was not included in defining my recommended ROE range.

IV. RETURN ON EQUITY FOR IDAHO POWER COMPANY

Q. What is the purpose of this section?

A. In addition to presenting the conclusions of my evaluation of a fair rate of return on equity for Idaho Power, this section also discusses the relationship between ROE and preservation of a utility's financial integrity and the ability to attract capital under reasonable terms on a sustainable basis.

A. Implications for Financial Integrity

Q. Why is it important to allow Idaho Power an adequate ROE?

A. Given the social and economic importance of the utility industry, it is essential to maintain reliable and economical service to all consumers. While Idaho Power remains committed to deliver reliable service, a utility's ability to fulfill its mandate can be compromised if it lacks the necessary financial wherewithal. Coupled with the ongoing potential for energy market volatility, Idaho Power's exposure to variations in hydroelectric generation and plans for significant infrastructure investment pose a number of potential challenges that might require the relatively swift commitment of significant capital resources in order to maintain the high level of service that customers have come to expect.

As documented earlier, the major rating agencies have warned of exposure to uncertainties associated with political and regulatory developments, especially in view of the potential for high and volatile commodity costs in competitive energy markets. Investors understand how swiftly unforeseen circumstances can lead to deterioration in a utility's financial condition, and stakeholders have discovered first hand how difficult and complex it can be to remedy the situation after the fact. For a utility with an obligation to provide reliable service, investors' increased reticence to supply additional capital during times of crisis highlights the necessity of preserving the flexibility necessary to overcome periods of adverse capital market conditions.

Q. What role does regulation play in ensuring Idaho Power's access to capital?

A. Considering investors' heightened awareness of the risks associated with the utility industry and the damage that results when a utility's financial flexibility is compromised, supportive regulation remains crucial to Idaho Power's access to capital. Investors recognize that regulation has its own risks, and that constructive regulation is a key ingredient in supporting utility credit ratings and financial integrity, particularly during times of adverse conditions. S&P concluded, "The political atmosphere will remain highly charged, fostering uncertainty."[70] Moody's echoed these sentiments, noting that "regulatory relationships are becoming more important" in an era of broadly rising costs and uncertainties,[71] and concluding:

> [T]here are concerns arising from the sector's sizeable infrastructure investment plans in the face of an environment of steadily rising operating costs. Combined, these costs and investments can create a continuous need for regulatory rate relief, which in turn can increase the likelihood for political and/or regulatory intervention.[72]

The rapid rise in wholesale energy prices has heightened investor concerns over the implications for regulatory uncertainty. The Wall Street Journal reported in May 2008 that escalating fuel costs were leading to soaring utility bills across the nation, raising the specter that social pressures could impact the outcome of regulatory proceedings.[73] S&P noted that, while timely cost recovery was paramount to maintaining credit quality in the utility sector, an "environment of rising customer tariffs, coupled

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[70] Standard & Poor's Corporation, "Top Ten Credit Issues Facing U.S. Utilities," *RatingsDirect* (Jan. 29, 2007).

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

[72] Moody's Investors Service, "Storm Clouds Gathering on the Horizon for the North American Electric Utility Sector," *Special Comment* (Aug. 2007).

[73] Smith, Rebecca, "Expect a Jolt When Opening The Electric Bill," Wall Street Journal at D1 (May 7, 2008).

with a sluggish economy, portend a difficult regulatory environment in coming years."[74]

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

A. Given the pressure on Idaho Power's financial metrics and its declining credit standing, which is exemplified by the negative outlook assigned by Moody's and Fitch, the perception of a lack of regulatory support would almost certainly lead to further downgrades. As Moody's concluded, "A key consideration in order for [Idaho Power] to stabilize its rating outlook and maintain its Baa1 senior unsecured rating will be the extent to which the IPUC is supportive in any future regulatory filings."[75]

At the same time, Idaho Power's plans include significant plant investment to ensure that the energy needs of its service territory are met in a reliable and cost-effective manner. Fitch noted that '[m]eaningful price increases will be required to recover planned capital expenditures to meet infrastructure and growth requirements,[76] while S&P cited "[r]egulatory challenges in meeting rising costs and a large capital expenditure

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[74] Standard & Poor's Corporation, "Top 10 U.S. Electric Utility Credit Issues For 2008 And Beyond," *RatingsDirect* (Jan. 28, 2008).

[75] Moody's Investors Service, "Credit Opinion: Idaho Power Company," *Global Credit Research* (June 4, 2008).

[76] Fitch Ratings, Ltd., "Idaho Power Company," *Global Power U.S. and Canada Credit Analysis* (Apr. 10, 2008).

program" as a key risk exposure.[77] While providing the infrastructure necessary to meet the energy needs of customers is certainly desirable, it imposes additional financial responsibilities on Idaho Power. To continue to meet these challenges successfully and economically, it is crucial that Idaho Power receive adequate support to buttress its credit standing.

Q. Do customers benefit by enhancing the utility's financial flexibility?

A. Yes. While providing an ROE that is sufficient to maintain Idaho Power's ability to attract capital, even in times of financial and market stress, is consistent with the economic requirements embodied in the Supreme Court's *Hope* and *Bluefield* decisions, it is also in customers' best interests. Ultimately, it is customers and the service area economy that enjoy the benefits that come from ensuring that the utility has the financial wherewithal to take whatever actions are required to ensure reliable service. By the same token, customers also bear a significant burden when the ability of the utility to attract necessary capital is impaired and service quality is compromised.

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[77] Standard & Poor's Corporation, "Idaho Power Co.," *RatingsDirect* (Feb. 1, 2008).

B. 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 Mr. Steve Keen. As summarized in his testimony, the common equity ratio used to compute Idaho Power's overall rate of return was approximately 49 percent in this filing.

Q. What was the average capitalization maintained by the Utility Proxy Group?

A. As shown on Exhibit No. 26, for the firms in the Utility Proxy Group, common equity ratios at December 31, 2007 ranged from 13.8 percent to 57.9 percent and averaged 43.3 percent. Value Line expects that the average common equity ratio for the proxy group of electric utilities will average 47.6 percent over the next three to five years, with the individual common equity ratios ranging from 29.0 percent to 59.5 percent.

Q. What implication do the uncertainties facing the utility industry have for the capital structures maintained by electric utilities?

A. As discussed earlier, utilities are facing energy market volatility, rising cost structures, the need to finance significant capital investment plans, uncertainties over accommodating future environmental mandates, and ongoing regulatory risks. Coupled with a decline in credit quality, these considerations warrant a stronger balance sheet to deal with an increasingly uncertain and competitive market. A more conservative financial profile, in the form of a higher common equity ratio, is consistent with increasing uncertainties and the need to maintain the continuous access to capital that is required to fund operations and necessary system investment, even during times of adverse capital market conditions.

Moody's has warned investors of the risks associated with debt leverage and fixed obligations and advised utilities not to squander the opportunity to strengthen the balance sheet as a buffer against future uncertainties.[78] Moody's recently noted that, absent a stronger equity cushion, utilities would be faced with lower credit ratings in the face of rising business and operating risks:

> There are significant negative trends developing over the longer-term horizon. This developing negative concern primarily relates to our view that the sector's overall business and operating risks are rising - at an increasingly fast pace - but that the overall financial profile remains relatively steady. A rising risk profile accompanied by a relatively stable balance sheet profile would ultimately result in credit quality deterioration.[79]

This is especially the case for electric utilities that are exposed to potential significant fluctuations in power supply costs, such as Idaho Power.

Q. What other factors do investors consider in their assessment of a company's capital structure?

A. Because power purchase agreements ("PPAs") and other contractual commitments typically obligate the utility to make specified minimum payments akin to those associated with traditional debt financing, investors consider a portion of these obligations as debt in evaluating total financial risks. Similarly, when a utility enters into a mandated PPA with a Qualifying Facility under PURPA, the

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[78] Moody's Investors Service, "Storm Clouds Gathering on the Horizon for the North American Electric Utility Sector," *Special Comment* (Aug. 2007).

[79] Moody's Investors Service, "U.S. Electric Utility Sector," *Industry Outlook* (Jan. 2008).

fixed charges associated with the contract increase the utility's financial risk in the same way that long-term debt and other financial obligations increase financial leverage.

Reflecting the longstanding perception of investors that the fixed obligations associated with off-balance sheet obligations diminish a utility's creditworthiness and financial flexibility, the implications of these commitments have been repeatedly cited by major bond rating agencies in connection with assessments of utility financial risks. For example, in explaining its evaluation of the credit implications of off-balance sheet obligations, S&P affirmed its position that such agreements give rise to "debt equivalents" and that the increased financial risk must be considered in evaluating a utility's credit risks.[80]

Q. What did you conclude with respect to the Company's capital structure?

A. Based on my evaluation, I concluded that Idaho Power's requested capital structure represents a reasonable mix of capital sources from which to calculate the Company's overall rate of return. Idaho Power's requested common equity ratio of approximately 49 percent is consistent with the range of capitalizations implied for the Utility Proxy

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[80] Standard & Poor's Corporation, "Standard & Poor's Methodology For Imputing Debt For U.S. Utilities' Power Purchase Agreements," *RatingsDirect* (May 7, 2007).

Group based on year-end 2007 data and Value Line's Line's near-term projections.

While industry averages provide one benchmark for comparison, each firm must select its capitalization based on the risks and prospects it faces, as well its specific needs to access the capital markets. A public utility with an obligation to serve must maintain ready access to capital under reasonable terms so that it can meet the service requirements of its customers. The need for access becomes even more important when the company has capital requirements over a period of years, and financing must be continuously available, even during unfavorable capital market conditions.

The decline in Idaho Power's credit standing and the heightened uncertainty associated with energy market volatility magnifies the importance of preserving financial flexibility. Idaho Power's capital structure reflects the Company's ongoing efforts to support its financial integrity and maintain access to capital on reasonable terms. As indicated earlier, the challenges posed by significant capital requirements, volatile energy prices, and reliance on hydro generation and wholesale markets magnifies the importance of preserving financial flexibility. The rating agencies have observed that Idaho Power's financial metrics have been under pressure, and utilities with higher leverage may be foreclosed from additional borrowing, especially during times of stress. In this regard, Idaho Power's equity ratio reflects the challenges posed by its resource mix, as well as the burden of significant capital spending requirements.

C. Return on Equity Recommendation

Q. Please summarize the results of your analyses.

A. Reflecting the fact that investors' required ROE is unobservable and no single method should be viewed in isolation, I considered the results of both the DCF and CAPM methods and evaluated comparable earned rates of return expected for utilities. In order to reflect the risks and prospects associated with Idaho Power's jurisdictional electric utility operations, my analyses focused on a proxy group of twenty-seven comparable risk electric utilities. Consistent with the fact that utilities must compete for capital with firms outside their own industry, I also referenced a proxy group of comparable risk companies in the non-utility sectors of the economy.

My application of the constant growth DCF model considered three alternative growth measures based on projected earnings growth, as well as the sustainable, "br+sv" growth rate for each firm in the respective proxy groups. In addition, I evaluated the reasonableness of the resulting DCF estimates and eliminated low- and high-end outliers that failed to meet threshold tests of economic logic. My CAPM analyses focused on forward-looking data that best reflects the underlying assumptions of this approach, as well as considering historical risk premiums. The results of my alternative analyses were summarized earlier in Table 4, which is reproduced below:

TABLE 4
SUMMARY OF QUANTITATIVE RESULTS

Method	Utility	Non-Utility
DCF	11.0%	12.6%
CAPM		
Forward-Looking	11.9%	11.2%
Historical	10.8%	10.2%
Comparable Earnings	11.1%	

Based on my assessment of the relative strengths and weaknesses inherent in each method, and conservatively giving less emphasis to the upper-most end of the range of results, I concluded that the cost of equity indicated by my analyses is in the 10.8 percent to 11.8 percent range.

Q. What then is your conclusion as to a fair ROE range for Idaho Power?

A. In evaluating the rate of return for Idaho Power, it is important to consider investors' continued focus on the unsettled conditions in restructured wholesale energy markets, the Company's ongoing exposure to these markets to meet a portion of its energy supply, as well as other risks associated with the utility industry, such as heightened exposure to regulatory uncertainties.

As explained above, I concluded that the fair rate of return on equity range was 10.8 percent to 11.8 percent. Considering capital market expectations, the potential uncertainties faced by Idaho Power, the Company's unique exposure to fluctuations in hydroelectric generation, and the economic requirements necessary to maintain financial integrity and support additional capital investment even under adverse circumstances, it is my opinion that this represents a fair and reasonable ROE range for Idaho Power. While this "bare-bones" cost of equity range does not consider issuance costs, a flotation cost adjustment is properly considered in establishing an allowed ROE for Idaho Power from within this range.

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

A. Yes.