BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC SERVICE TO ELECTRIC CUSTOMERS IN THE STATE OF IDAHO.	)	CASE NO. IPC-E-05-28

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

DENNIS C. GRIBBLE

Q. Would you state your name, address and present occupation?

A. My name is Dennis C. Gribble and my business address is 1221 West Idaho Street, Boise, Idaho. I am employed by Idaho Power Company as Vice President and Treasurer.

Q. What is your educational background?

A. I graduated in 1975 from Boise State University, Boise, Idaho, receiving a Bachelor of Business Administration degree in Economics. In 1978, I graduated from Boise State University, Boise, Idaho, with a Master in Business Administration. In 1989, I completed the University of Idaho's Public Utilities Executive Course in Moscow, Idaho. I have also attended numerous seminars and conferences on accounting and finance issues related to the utility industry. I am a Certified Treasury Professional.

Q. Would you please describe your business experience with Idaho Power Company?

A. I joined Idaho Power Company (the Company) in 1979. In June 1982, I transferred to the Finance and Reporting Services Department as a Business Analyst. In June 1986, I was promoted to a Business Analyst Supervisor. In March 1991, I was promoted to Manager of Financial Services. In January 1992, I was promoted to Manager of Corporate Accounting and Reporting. In 1996, I was promoted to Controller-Financial Services, in October 2003 I was promoted to Assistant Treasurer, and in July 2004, I was promoted to my current position as Vice President and Treasurer.

In the course of my duties with Idaho Power Company, I have presented testimony to the Idaho Public Utilities Commission (IPUC) and the Oregon Public Utility Commission.

Q. What are your duties as Vice President and Treasurer as they relate to the current proceeding?

A. I oversee the direct financial planning, procurement, and investment of funds for Idaho Power, as well as supervise corporate liquidity management.

Q. What are your financial activities and responsibilities with respect to Idaho Power Company?

A. My activities and responsibilities include various aspects of all the Company's financings and other financial matters. With respect to long-term financings - sale of bonds, preferred stock, and common stock - my activities include development of financial plans with senior officers, meeting with representatives of investment banking firms that are interested in underwriting our securities, discussions with rating agencies, assisting in preparation of financial material including Registration Statements filed with the Securities and Exchange Commission, representing the Company at information meetings for investment banking firms, reviewing recommendations on bids received relative to the Company's financings and recommending disposition of net proceeds. With respect to short-term financings, these activities and responsibilities include negotiation of lines of credit with commercial banks and arranging for the sale of commercial paper.

Q. Are you in continual communication with members of the financial community?

A. Yes. I am in constant contact with individuals representing investment and commercial banking firms, rating agencies, insurance companies, institutional investment firms, and other organizations interested in publicly traded securities, that actively follow IDACORP and Idaho Power Company. In association with the Chief Financial Officer and the Director of Investor Relations, my responsibilities include keeping these persons informed of the Company's financial condition, arranging meetings with these people and Idaho Power's senior executive management, and visiting with financial representatives in their respective offices. Some of these members of the investment community have followed the electric utility industry for an extended period of time and have a great deal of expertise in the financial problems and prospects of utilities.

Through my continual contact with the financial community, and review of investment banking analytical reports and articles issued by these firms, I am able to keep informed on trends, interest rates, financing costs, security ratings, and other financial developments in the public utility industry.

Q. Are you a member of any professional societies or associations?

A. Yes. I am a member of the Association for Financial Professionals and the Institute of Management Accountants.

Through information received from attendance at conferences and seminars of these and other utility professional groups such as the Edison Electric Institute, I am able to gain additional insights into the financial developments affecting Idaho Power Company as well as the electric utility industry.

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

A. I am sponsoring testimony as to the point estimate for Idaho Power Company's rate of return on common equity and the embedded cost of long-term debt, the use of an estimated year-end 2005 capital structure, and the resultant overall cost of capital to be used in these proceedings.

Q. What exhibits are you sponsoring?

A. I am sponsoring Exhibits numbered 10 through

13.

Q. Did you testify before the Idaho Public Utilities Commission in the Company's last general rate application?

A. Yes.

Q. Are you aware that the Commission in Order No. 29505 issued May 22, 2004, found a return on Equity of 10.25% to be reasonable?

A. Yes.

Q. What are you recommending in this proceeding?

A. I have selected 11.25 percent as a reasonable cost of equity for the Company, which falls within Mr. Avera's recommended cost of equity range for Idaho Power Company of 11.0 to 12.0 percent.

Q. Could you briefly outline what conditions have changed to warrant an increase in common equity from the Commission ordered 10.25% to your recommended 11.25%?

A. As I will discuss in my testimony, I believe a 11.25% return on equity reflects a fair return to the Company's shareholder when taking into account the risks associated with; (1) the continued drought that the Company is experiencing and the associated level of non-recoverable excess power supply costs, (2) the recent downgrade of the Company's debt ratings, (3) the substantial upcoming construction and associated capital outlays that confronts the Company, (4) the risks related to relicensing the Company's hydro-electric projects (especially the Hells Canyon Complex), and (5) the effect of purchased power contracts with PURPA Qualifying Facilities (QFs).

Q. Are some of these conditions the same conditions that you testified to in the last Idaho Power rate proceeding?

A. Yes, and I will update those conditions to explain what has changed due to the passage of time.

Q. What is the overall cost of capital for Idaho Power Company?

A. Based on an estimated year-end 2005 capital structure provided to me by Ms. Smith, the embedded cost of capital presented in my testimony, and incorporating the 11.25% percent cost of equity, the resultant overall cost of capital for Idaho Power Company is 8.420 percent.

Q. Mr. Avera indicates in his testimony that Idaho Power, when compared to the Western electric utility industry and its selected comparable peer group, has a greater share of specific risk. Do you agree with this conclusion?

A. Yes. In terms of the overall industry risk, financial analysts, bond rating agencies, regulators, and other commentators in the financial press chronicle the exceptional volatility of change and risk in the western electric utility industry. The Company, not unlike the majority of the industry, also faces the prevalence of change and uncertainty. Most observers agree that individual companies tend to have increasingly less and less control of both the pace and magnitude of this change and uncertainty. In addition to the impact of the general electric utility industry risk, Idaho Power Company does face very specific risks.

Q. What are these risks specific to Idaho Power Company?

A. The following are risks that the investing public view as specific to Idaho Power Company: (1) a predominately hydroelectric generating base subject to the vagaries of weather, water, and a volatile wholesale power supply market in the Western United States and specifically the Northwest, (2) the renewal of federal licenses for its hydroelectric projects, namely the Hells Canyon Complex which provides 40 percent of the Company's total generating capacity, (3) the ability to recover significant capital investment required for present and growing electrical requirements and service reliability for its customers, and (4) the impact of QF related expenditures.

Q. Can you elaborate as to the nature of Idaho Power Company's risks?

A. Yes. I will provide additional detail on each specific risk and also provide the financial investing communities perspective relative to that risk. Thomas Hamlin, an equity analyst with Wachovia Capital Markets, LLC Equity Research, succinctly states these specific risks in his May 23, 2005 research report (pg.10); "The following factors could have a significant impact on the operations and financial results of IDACORP: Reduced Hydro Conditions; State Regulatory Commission Actions; Conditions imposed on hydro license renewals; Litigation; and Environmental Regulations."

Q. Please describe the risks specific to a predominately hydroelectric generating base subject to the vagaries of weather and water.

A. Idaho Power Company and its customers have often enjoyed the benefits of a hydroelectric-based utility. However, because of the heavy reliance on hydroelectric generation, the Company's operations and resulting financial condition can be significantly impacted by low water conditions. Reduced hydroelectric generation resulting from below normal water flows requires the Company to use more expensive thermal generation and/or purchased power to meet the electrical needs of its customers. Although the IPUC grants recovery for the majority of extraordinary purchased power costs through the Company's Power Cost Adjustment Mechanism (PCA), the recovery is less than 100 percent and is subject to the regulatory process. Generally, the investment community views the PCA as a positive mechanism since it does allow for recovery of the majority of excess net power supply costs. As a result of the 2000-2001 California energy crisis and six years of Northwest drought conditions, recent PCA rate proceedings have reflected the Company's unprecedented increased net power supply costs. Although originally conceived as a symmetrical mechanism, the Idaho jurisdictional 10 percent portion of the recent PCA proceedings borne by the Company's shareholders has had a significant financial impact on the earnings capability of the Company because actual results have not been symmetrical. When compared with more familiar fuel cost adjustment mechanisms (such as those frequently associated with gas utilities) that recover 100 percent of changes in base fuel costs, the Company's PCA mechanism with its 90%-10% cost sharing feature, is viewed by the investment community as more risky. Paul T Ridzon, Equity Research Analyst with KeyBank Capital Markets indicated in his January 6, 2005 research report (pg. 5), "PRIMARY RISK FACTORS - We consider IDA's primary investment risk to be earnings volatility related to the impact of variable precipitation levels on its sizable (1,700 MW) hydroelectric generation fleet. During periods of reduced streamflow, IDA depends on more costly sources of power to meet its load requirements. IDA absorbs or retains the first 10% of higher power supply costs (or benefit) relative to a benchmark stemming from variation in power supply costs. This risk has been highlighted by five consecutive years of below normal precipitation."

Q. Please describe the risks specific to the renewal of federal licenses for the Company's hydroelectric projects.

A. Idaho Power Company is the only investor-owned electric utility in the United States with 55 percent of its generation derived from hydro generating facilities under normal water conditions. With such a large portion of the Company's generation resources based on hydro facilities, a negative economic impact resulting from renewing the Federal licenses of these facilities could have a significant financial impact on the Company and the prices its consumers pay for electricity. As part of this process, the Company has filed and will file applications with the Federal Energy Regulatory Commission (FERC) for new licenses for its hydro generating capacity.

Q. What are the associated financial risks to the Company from relicensing its hydro generating capacity?

A. Once an application is filed, the time frame to actually receive an order from the FERC is unknown. The combinations of an unknown time frame to receive a new license, loss of generation capability due to operational changes, and the financial impact of unknown Protection, Mitigation, and Enhancement (PM&E's) costs are financial risks unique to the Company.

Q. Please address the risk associated with the Company's relicensing effort for the Hells Canyon generating facilities.

A. The Hells Canyon generating facilities comprised of Hells Canyon, Oxbow, and Brownlee dams make up 67 percent of the Company's hydro generation capacity and 40 percent of its total generation capacity. The Hells Canyon license application was filed in July of 2003, and with a FERC process that moves at a slow and deliberate pace due to the large number of interested parties involved in evaluating the application, the likelihood of a new Hells Canyon facilities license being issued in the near future is remote. Historically in these types of delayed situations, the Company has been given an annual license renewal (under the existing old license) until the formal new license is issued. This delay further reinforces the ambiguity of the ultimate financial impact. At June 30, 2005, $71 million of Hells Canyon Complex relicensing costs are included in construction work in progress. Under current Idaho statute, this investment is not included in the Company's rate base. Based upon the Company's Hells Canyon relicensing application, the estimated costs of PM&E's for the Hells Canyon Complex relicensing are approximately $106 million in the first five years of a license and $218 million over the following twenty-five years, for a total estimated cost of $324 million over a thirty-year license.

Q. Are there other hydro relicensing-based financial risks considered by the investment community?

A. Yes. For any particular generating facility, the worst possible outcome would be the loss of the license to a competing party. Along with the uncertainty as to the eventual receipt of licenses and the costs involved in preparing for the license applications, costs of PM&E's related to these projects are also difficult to quantify. The potential financial magnitude of these PM&E's and their effect on the Company's low cost hydrogeneration resources threaten the financial stability of a company the size of Idaho Power and the ultimate rates it must charge its customers. These amounts will vary between each facility, but in all cases they can be significant due to lost generation capacity, less generation at a higher cost, and the decreased ability of the Company to time and control water releases. If the Company cannot generate when it is most advantageous for the system, then some of the economic value of the generation has been lost, even if the amount of total generation does not change. In addition to the hydro relicensing risk, the Company continually faces significant capital, operating and other costs associated with compliance with current environmental statutes, rules and regulations. These costs may be even higher in the future as a result of, among other factors, changes in legislation and enforcement policies and the potential additional requirements imposed in connection with the relicensing of the Company's hydroelectric projects. Kevin Rose, an analyst with credit rating agency Moody's Investor Services notes in his May 11, 2005 Summary Opinion update on Idaho Power Company (Pg. 1); "Credit challenges for IPC are: Costs and potential operational changes tied to the hydroelectric plant relicensing process."

Q. Why do you say that a volatile wholesale power supply market in the Western United States and specifically the Northwest is a risk specific to Idaho Power Company?

A. The persistent drought in the Northwest has specifically impacted the Company in several ways. These impacts are: first, and as noted above, reduced access to the Company's low cost hydroelectric generation, second, increased reliance on the Company's thermal-based generating resources, and lastly, the heightened exposure to volatile wholesale energy prices when the Company must rely on the wholesale energy market to meet native load requirements.

When the Company is unable to utilize its hydro resources, it must next turn to the wholesale markets or its own thermal-based resources. Typically pricing and availability will determine these decisions. Over the last several years, the Company's thermal fleet has been required to supply a large amount of the resource deficit since the wholesale energy market prices were extremely high and hydro availability was low. Although these aging thermal resources have been available when needed, they are requiring increased capital and operation maintenance expenditures just to maintain availability. As the reliability of these thermal resources diminishes, either as a result of age or over-utilization, the Company is further at the mercy of a volatile Western and Northwest energy market. James L Bellesa, research analyst for D.A. Davidson & Co., describes this situation in his April 11, 2005, research report (pg. 1), "LOWERING EPS PROJECTIONS AGAIN FOR DROUGHT AND COST PRESSURES…, We are significantly decreasing our 2005 and 2006 EPS projections for IDACORP. We believe the effects of a 6-year drought are increasingly combining with rising operating expenses to reduce the outlook for utility earnings below our previous forecasts…."

Q. Please describe the risks specific to the Company's ability to recover significant capital investment required for present and growing electrical requirements and service reliability for its customers.

A. As the Company's generation and transmission systems age and customer electrical requirements increase, additional investment is required to meet reliability standards and the additional demand on its electrical infrastructure. The Company's latest forecast requires construction budgets of approximately $200 million in 2005 and $672 million for 2005 through 2007 combined. Recovery of these investments introduces two elements of risk. First, the ability of the Company to attract the required capital, and second, the recovery of these investments is on a deferred basis and subject to the regulatory process. As mentioned previously in my testimony, Kevin Rose, an analyst with Moody's Investor Services notes in his May 11, 2005 Summary Opinion update on Idaho Power Company (Pg. 1); "Credit Challenges - Credit challenges for IPC are: Overcoming lower than requested rate increase approved against a backdrop of customer growth, additional capacity needs, and plans to expand the T&D system; Costs and potential operational changes tied to hydroelectric plant relicensing process; Coping with effects of drought and unfavorable weather; and, Obtaining supportive regulatory outcomes in expected future filings for rate increases."

Q. How does the regulatory treatment of QF related expenditures increase the financial risk to Idaho

Power?

A. The regulatory treatment of QF expenditures provides for a one for one recovery of dollars expended, but does not provide for a return on equity to compensate the Company for this activity. The Company is, in effect, buying and selling energy under its QF mandated transactions with no remuneration. Simplistically, this regulatory treatment is similar to requiring a person operating a fruit stand to buy watermelons for $1.00 and providing they must be sold for $1.00. The mere dollar for dollar recovery of QF expenditures, but no return for the use of the Company's balance sheet and liquidity in managing QF programs, is viewed as a significant risk by the rating agencies. They are not making a judgment related to the appropriateness of QF programs, but merely pointing out the cost of the financial risk(s) of a QF program should be reflected in a higher return on equity to credit the company for its management of QF programs.

Q. Has the Commission considered in the past a proposal to compensate the company for its management of QF programs?

A. Yes. In determining the appropriate rates to be paid for power and energy sold to Idaho Power pursuant to section 210 of the PURPA Act of 1978, the Commission through Order 18190 at page 21 indicated: "In another context, Staff witness Drummond proposed that Idaho Power be given a management fee amounting to 5% of the gross payments made to CSPP's. The Commission will do all in its power to encourage Idaho Power to manage such projects in an orderly fashion. Orderly management includes adequate staffing and clear lines of authority among personnel assigned to deal with CSPPs; good faith negotiating of contracts and expeditious processing of worthy applications; and, above all, a showing that the Company has integrated cogeneration and small power resources into its own planning, construction and financing programs. When orderly management is demonstrated, the Commission will reconsider the question of an appropriate management fee or an equity adjustment". The current expected normalized cost for QF purchases is approximately $46.4 million. A 5% management fee on these normalized QF costs would result in a payment to the Company of approximately $2.3 million. Using $935.1 million as the equity level assumed in this filing, the 5% management would yield an additional ROE of approximately 15 basis points.

Q. Do the rating agencies recognize the financial costs of QF related transactions?

A. Yes. Like other electric utilities, when the Company adds to its rate base, it must use some portion of shareholder equity to fund the investment. The Company must maintain its equity component above a certain level as it continues this investment process. If it does not, the debt level increases and the Company will face the threat of a bond rating downgrade. Conversely, when the Company enters into a QF contract for purchased power, an obligation not reflected in its financial statements, an increase in equity is needed to maintain credit quality. Unless an equity component is provided to offset the debt-like obligation of long-term QF purchase power contracts, the Company faces off-balance sheet financial risk. For financial commitments that do not appear on the balance sheet, credit rating analysts impute the debt and interest equivalents on the financial statements of the Company to achieve a more accurate picture of the risk associated with their investment. The added equity needed to offset this imputed debt and interest represents the effect that long-term purchased power commitments have on the cost of capital. Any increase in the long-term obligation of a utility related to its capacity and energy resources will have to be backed by an appropriate amount of equity in the eyes of the investment community.

In reviewing its evaluation of the credit implications of QF related expenditures, S&P recently affirmed its position that such agreements are "debt-like in nature" and that the increased financial risk must be considered in evaluating a utility's credit risks. As the rating agency explained in its publication, Utilities & Perspectives, May 12, 2003,

"[P]urchased power agreements typically result in the assumption of fixed costs representing the portion of the purchase price that is linked to the capacity component of the total payment. These fixed capacity payments are similar to debt service payments incurred by a utility that constructs debt-like financed power generation facilities. Therefore, whether a utility builds its own generation plants, or enters into a long-term power purchase agreement with a fixed-cost component, that utility is taking on financial risk."

Q. What is the status of Idaho Power Company's bond ratings?

A. The ratios for Idaho Power Company at the conclusion of the last general rate application in Idaho (IPC-E-03-13) as compared to the current coverage ratings that reflect recent downgrades by all three of the major credit rating agencies are as follows:

	Moody's		S & P		Fitch Ratings	
	Prior	Current	Prior	Current	Prior	Current
Corporate	A3	Baa	A-	BBB+	No Rating	
FMB's	A2	A3	A	A-	A	A-
Preferred	Baa2	Baa3	BBB	BBB-	BBB+	BBB
CP(S/T Debt)	P-1	P-2	A-2	A-2	F-1	F-2

Q. Why did the rating agencies downgrade Idaho Power Company?

A. The three major credit rating agencies, Moody's, Standard & Poor's, and Fitch all issued a downgrade for Idaho Power in late 2004 and early 2005. I have included the reports by each of these rating agencies explaining their rationale for these downgrades as Exhibit 10.

Q. What was the rationale supporting Moody's Investor Services recent downgrade of the Company's bond rating?

A. Kevin Rose, Vice President and Senior Analyst for Moody's, describes the action in his December 3rd, 2004 report (page 1), "The downgrade of IPC's ratings reflects: 1) expected weaker cash flow coverage of interest and debt; 2) the likelihood for continued negative free cash flow over the next few years, with internally generated funds falling short of meeting dividend requirements of IDACORP and significant utility-related capital spending; 3) persistent drought conditions that are likely to result in higher supply costs, not all of which are recoverable under the utility's power cost adjustment mechanism; 4) the final resolution this fall of the company's rate case, which resulted in a revenue increase of a little more than half of the company's updated request, and; 5) the likely need for additional support from the Idaho Public Utilities Commission (IPUC) in future rate proceedings as IPC adds new generation and transmission infrastructure to help meet customer and load growth and ensure reliability of service."

A. Standard & Poors also recently downgraded the Company's bond rating. What prompted this rating agency to take such an action?

Q. Swami Venkataraman, an analyst with the credit rating agency Standard and Poor's, cites similar rationale in his report dated November 29, 2004 and also indicates that (page 2), "…. These pressures resulted in a financial profile that is weak for even the BBB+ rating. Management is attempting to reduce costs and is planning to file a general rate case in 2006 to strengthen IDACORP's financial profile."

Q. A third rating agency also downgraded the Company's bond rating earlier this year. What were the factors driving this downgrade?

A. Philip W Smyth, analyst with the credit rating agency Fitch Ratings, noted in his February 18, 2005 report similar references to "adverse effects of the southern Idaho drought…, earnings volatility inherent in the utility's hydro generation system…, a disappointing outcome in IPC's 2004 general rate case", but also noted the favorable aspects of the company's PCA mechanism "which has enabled the company to maintain solid interest rate coverage ratios". Mr. Smyth also noted on page 1 of this report that, "The ratings were also positively affected by a more conservative corporate business profile at IPC's corporate parent, IDACORP, Inc. (IDA), and ongoing efforts to reduce financial leverage, including a net $116 million common stock offering in December, 2004. A portion of the proceeds from the common stock issuance were used to reduce utility debt and to fund future utility capital expenditures."

Q. What have been the implications of these downgrades to Idaho Power?

A. The Company believes that maintaining a strong "A" rating is essential and was obviously disappointed with the downgrade actions taken by these rating agencies. The Company must maintain its ability to attract capital in the current ultra-competitive investing environment. Idaho Power is not a large electric utility and when matched against other utility investment opportunities, the Company lacks the benefit of broad investment analyst coverage. Although a "BBB" rating for the Company has not precluded the Company from accessing the capital markets, it has meant cost increases on newly issued long-term debt and has elevated the risk profile for the Company in accessing the lower-cost short-term commercial paper market. In simple terms, the Company's objective to have a strong "A" rating helps Idaho Power to maintain its independence and attract lower cost capital as the Company faces immediate substantial investment requirements. In the face of the downgrades, if the Company cannot regain its "A" rating, the cost of capital will be higher for the company and its customers.

Q. What changes have occurred in the capital structure of the Company since the last general rate application in Idaho?

A. At the time of the last Idaho general rate case, the Company's weighted cost of debt and preferred stock were 2.946 percent and .194 percent, respectively. As will be shown later in my testimony, the Company's current weighted cost of debt and preferred stock is 2.856 percent and zero percent, respectively. IDACORP issued approximately $116 million in new common equity in December 2004. This new common equity was issued to help stabilize ratings (even though a resultant downgrade occurred), and infused approximately $85 million of new equity into Idaho Power. This has resulted in an increase in the level of common equity at Idaho Power from 45.971 percent as found in

IPUC Order 29505 to 49.462 percent in this application. Although this increase in the amount of equity increases the overall cost of capital it was necessary to prevent further erosion in the debt ratings of Idaho Power. As discussed in Mr. Avera's testimony, this percentage of common equity in the capital structure is within the range of reasonableness for the Company's peer group. The ordered overall cost of capital at the last Idaho general rate case was 7.852 percent and is increased in this filing to 8.420 percent. This increase is directly related to the increased level of common equity and the recommended return on equity of 11.250 percent.

Q. Would you please comment on Exhibit No. 11?

A. Exhibit No. 11 details the calculation of the Idaho Power Company capital structure for long-term debt, preferred stock, and common equity balance resulting from the Company's estimated year-end 2005 capital structure as provided to me by Ms. Smith.

Q. Earlier in your testimony you indicated that you have used an estimated 2005 financial result in arriving at the overall cost of capital for the Company. Why have you selected this particular capital structure?

A. The estimated year-end 2005 financial results as provided to me by Ms. Smith reflect the Company's best estimate of the 2005 year-end capital structure. This approach is identical to the one used during the last general rate case (IPC-E-03-13). The Commission, if it desires, can update the capital structure to incorporate known and measurable changes as the proceeding progresses to reflect an actual year-end 2005 capital structure. Mr. Avera, in his testimony, has indicated that the capital structure submitted on my Exhibit No. 11 is reasonable and is consistent with comparable companies in the industry.

Q. The capital structure presented on Exhibit No. 11 incorporates changes to the Company's normal financial reporting of its capital structure. Could you please discuss the rationale for the variance?

A. For financial reporting purposes, the American Falls Bond Guarantee and the Milner Dam Note Guarantee are included in the long-term debt portion of the capital structure. For ratemaking purposes the interest costs associated with both the American Falls and the Milner debt securities are covered as operating and maintenance ("O&M") expenses. Even with these exclusions, the capital structure presented in my Exhibit No. 11 is reasonable in light of industry and rating agency criteria.

Q. Would you please comment on Exhibit No. 12?

A. Exhibit No. 12 details the calculation of the embedded cost of debt used in the estimated year-end 2005 capital structure. The embedded cost of debt is 5.651

percent.

Q. Does the Company utilize variable rate securities in its long-term capitalization?

A. Yes, the Company currently utilizes several variable rate securities in its long-term capitalization. These securities are the County of Sweetwater Variable Rate Series 1996B ($24.2 million), and 1996C ($24.0 million) Pollution Control Bonds, the Port of Morrow Variable Rate Pollution Control Bonds ($4.36 million), and the Humboldt County Pollution Control Revenue Bonds ($49.8 million). These securities are listed on lines 13, 14, 15, and 16 on Exhibit No. 12.

Q. Would you please describe the variable rate nature of these variable rate pollution control bonds?

A. These variable rate pollution control bonds, although considered long-term securities, have features that allow the Company to take advantage of rates applicable to short-term securities. The County of Sweetwater Pollution Control Variable Rate Bonds Series B and C (Bridger Variable Rate Bonds) reset the interest rate on a daily basis. The Port of Morrow Pollution Control Variable Rate Bonds (Boardman Variable Rate Bonds) reset the interest rate on a weekly basis. The Humboldt Pollution Control Revenue Bonds (Valmy Variable Rate Bonds) reset their interest rate every 35 days. The Bridger Variable Rate Bonds daily interest rate is determined each business day by a Remarketing Agent. The rate is set via review of other comparable tax-exempt obligations recently priced or traded under then-prevailing market conditions. This rate than would become the lowest rate which would enable the Remarketing Agent to sell the Bridger Variable Rate Bonds. Likewise, on a weekly basis the Boardman Variable Rate Bonds weekly interest rate is determined the first day of a weekly period by a Remarketing Agent. Again, the Remarketing Agent examines tax-exempt obligations comparable to the Boardman Variable Bonds known to have been priced or traded under the then-prevailing market conditions and finds the lowest rate which would enable sale of the Boardman Variable Rate Bonds. The Valmy Variable Rate Bonds reset their interest rate every 35 days via a dutch auction process (lowest bid received by an Auction Agent that covers the bonds outstanding) to reflect the current market conditions.

Q. Please comment on the derivation of the effective cost of the interest rates for the Pollution Control Bonds listed on lines 13, 14, 15, and 16 of Exhibit No. 12?

A. Page 1 of Exhibit No. 13 is a chart that depicts the Bond Market Association (BMA) Municipal Swap Index for the last 5 years. The BMA Municipal Swap Index, produced by Municipal Market Data (MMD), is a 7-day highgrade market index comprised of tax-exempt Variable Rate Demand Obligations (VRDO’s) from MMD’s extensive database. The Index was created in response to industry participants' demand for a short-term index to accurately reflect activity in the VRDO market.

Page 2 of Exhibit No. 13 shows the Company’s average spreads (difference of the Company’s actual variable rate, plus or minus, when compared to the BMA Municipal Swap Index) over the BMA Municipal Swap Index for the Bridger Variable Rate Bonds and the Boardman Variable Rate Bonds over the last five years.

In light of the volatility in short—term interest rates, I determined (and the Commission utilized in determining the cost of capital in Order 29505) that an average of the 5 year BMA Municipal Swap Index, plus an average of the Company’s spreads over that same five year period of these variable rate bonds, should be used in calculating the coupon rate of these securities for rate determination purposes. This is a conservative approach and is consistent with the methodology adopted by the Commission in the last rate case (IPC-E-03-13).

The average of the 5 year BMA Municipal Swap Index is 1.90 percent, the average 5 year Company spreads for the Bridger Variable Rate Bond Series B is 0.09 percent, the Bridger Variable Rate Bond Series C is 0.06 percent, the

Boardman Variable Rate Bond is 0.94 percent, and the Valmy Variable Rate Bonds is -0.11 percent. The resulting variable rate securities coupon and effective costs for ratemaking purposes are:

	Implicit Coupon	Effective
Bridger Variable Rate Bond Series B	1.980%	2.000%
Bridger Variable Rate Bond Series C	1.960%	1.985%
Boardman Variable Rate Bond	2.830%	2.912%
Valmy Variable Rate Bond	1.790%	1.853%

Q. Would you please comment on the removal of preferred stock from the Company's capital structure.

A. After consultation with various rating agencies and discussing the matter with the IPUC staff, the Company determined that preferred stock provided little value to the overall cost of capital. Preferred stock is essentially treated as debt by the rating agencies (although some forms of preferred stock theoretically provide a portion of equity), its dividend is not tax deductible, and typically has a higher overall higher cost of capital than debt. In August 2004, the Company issued $55 million of 30 year First Mortgage Bonds at 5.875% and used the proceeds to economically retire in September 2004, approximately $50 million (and associated premiums) of the Company's existing 4.0%, 7.07%, and 7.68% preferred stock. The cost of preferred stock has now been reflected as zero in the

Company's overall cost of capital.

Q. What is the overall weighted cost of capital when you incorporate the respective costs?

A. The overall weighted cost of capital for revenue requirement purposes in this proceeding is 8.420 percent. This is based on a 5.651 percent embedded cost of debt; and the 11.250 percent rate of return on common equity.

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

A. Yes, it does.