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IDAHO PUBLIC
UTILITIES COMMISSION

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

STEVEN R. KEEN

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

A. My name is Steven R. Keen 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 with high honors in 1981 from Idaho State University, Pocatello, Idaho, receiving a Bachelor of Business Administration degree in Accounting. I have also attended numerous seminars and conferences on accounting and finance issues related to the utility industry. I am a Certified Public Accountant licensed in the State of Idaho.

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

A. I joined Idaho Power Company ("Idaho Power" or the "Company") in September, 1982, in the Property Accounting Department. In March 1983, I transferred to the Tax Department as a Tax Accountant. From that time through December 1998, I advanced through every position in the Tax Department including Property Tax Representative, Tax Research Coordinator, and, finally, Corporate Tax Director. In January 1999, I became President of IDACORP Financial

Services. In June of 2006, I accepted the position of Vice President and Treasurer of Idaho Power Company and IDACORP, Inc.

In the course of my duties with Idaho Power Company, I presented testimony in Idaho Power's last general rate case in Idaho, Case No. IPC-E-07-08. I have also presented tax testimony to the Internal Revenue Service as well as tax and/or capitalization rate testimony to the Departments of Revenue and Taxation for Idaho, Oregon, Wyoming, and Nevada.

Q. What are your duties as Vice President and Treasurer of Idaho Power as they relate to this proceeding?

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

My duties and responsibilities include various aspects of all the Company's financings and other financial matters. With respect to long-term financings, sale of bonds and equity, my duties include development of financial plans with senior officers, meeting with representatives of investment banking firms that are interested in underwriting Idaho Power securities, discussions with credit 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 information relative to the Company's financings and recommending disposition of net proceeds. With respect to short-term financings, these duties and responsibilities include negotiation of lines of credit with commercial banks and overseeing the sale of commercial paper.

Q. Do your responsibilities include communication with members of the financial community?

A. Yes. I am in continuous contact with individuals representing investment and commercial banking firms, credit 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 Company's 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 and the rating agencies, 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 current member and past board president of the Idaho Society of Certified Public Accountants. I am a current member of and past council member of the American Institute of Certified Public Accountants. I am a current member and past board chairman of the Associated Taxpayers of Idaho. I am also the current chairman of the Board of the Idaho Tax Foundation. I am a member of the Idaho Association for Financial Professionals.

I also receive information from attendance at conferences and seminars of these and other utility professional groups such as the Edison Electric Institute. Through participation in these events, I 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, risk factors generally and that are unique to Idaho Power Company, the use of a forecasted year-end 2008 capital structure, and the resultant overall cost of capital used to compute the Company's revenue requirement.

Q. What exhibits are you sponsoring?

A. I am sponsoring Exhibits numbered 27 and 28.

COST OF EQUITY POINT ESTIMATE

Q. What return on equity are you recommending in this proceeding?

A. I have selected 11.25 percent as the point estimate for cost of equity for the Company.

Q. Does that point estimate align with the recommendations made by the Company's cost of capital witness Mr. Avera?

A. It does. The Company's expert witness has recommended a range of between 10.8 and 11.8 percent, excluding the effects of flotation. I have selected a percentage within his recommended range that I believe is appropriate given the concepts put forth by the Company in this case. Elements of our submitted case include requests for reduced regulatory lag and accelerated cash recovery for the carrying cost of a portion of Construction Work in Progress ("CWIP"). Both of these proposals, if accepted by the Commission, would tend to lower the Company's risk profile and warrant a cost of equity below the upper end of Mr. Avera's range.

Q. If those concepts are not accepted and not included in a final rate order would that impact your recommendation on the point estimate?

A. Yes. Without those enhancements I would be recommending a point estimate higher in Mr. Avera's recommended range.

Q. Are there other issues that could potentially influence your recommendation?

A. Yes. There are planned workshops focusing on various issues that impact the Company's ability to earn its allowed rate of return. The impacts of the Load Growth Adjustment Rate ("LGAR") will be addressed along with certain other potential changes to the Power Cost Adjustment ("PCA") mechanism. If these issues are resolved in a manner that lessens the negative impacts on the Company, my recommended cost of equity would move lower. If the outcome of these workshops significantly reduces the

Company's exposure to the variability of power supply costs and the Company is no longer penalized for bearing the burden of accommodating growth in our service territory, I could support a lower cost of equity within Mr. Avera's recommended range. However, that recommendation could only be made if the workshops result in a favorable order to the Company that lowers risk.

RISK FACTORS

Q. Could you briefly outline what conditions require a return on common equity of 11.25 percent?

A. Yes. I will summarize them here and discuss them in greater detail later in my testimony. In addition to the reasons advanced by Mr. Avera, I believe that, at a minimum, an 11.25 percent return on equity is required to properly account for the risks confronting Idaho Power Company, namely: (1) the significant variability in power supply costs that exists due to a predominately hydroelectric generating base subject to the uncertainties of weather and water, (2) the effects of pricing changes in a volatile wholesale power supply market in the Western United States and specifically the Northwest, coupled with its effect on the PCA mechanism (3) the impacts related to the current methodology utilized in the LGAR in the PCA, (4) the persistence of water issues and water litigation in

Idaho, (5) the renewal of federal licenses for the Company's hydroelectric projects, primarily the Hells Canyon Complex, which provides 40 percent of the Company's total generating capacity and particularly the significant cost of relicensing that project, (6) the impact of Qualified Facility ("QF") related expenditures, (7) the inability of the Company to recover the significant capital investment required for present and growing electrical requirements and service reliability for its customers on a timely basis, (8) the general decline in credit quality of the Company, and (9) the inability of the Company to earn an actual return on capital that is anywhere near a reasonable allowed rate of return.

Q. Are some of these risk conditions the same risk conditions that have been raised in past Idaho Power rate proceedings?

A. Yes. These risks still exist and the passage of time has exacerbated their potential impact on the Company.

Q. Are there other risks, less specific to Idaho Power Company, that also impact your recommendation?

A. Yes. There are general financial risks such as increased volatility in the financial markets and what I view as a heightened sensitivity to risk exposure that has evolved since the U.S. housing market began experiencing problems in 2007. There are also industry specific risks, such as unknown costs relative to carbon emissions, an industry-wide need for infrastructure improvements, and increased capital investment as well as inflationary pressures that increase costs of both operating expenses and capital outlays. All of these factors combine to make a challenging environment in which the Company must compete with others in the electric utility industry, for both resources and capital, to serve the needs of its customers and shareowners. While I do not intend to elaborate further on these risk areas, they are factors worthy of notation that point to an increased level of risk exposure for the Company.

1. Hydro Variability

Q. Please describe the risks specific to Idaho Power's predominately hydroelectric generating base which is subject to the uncertainties of weather and water.

A. Idaho Power Company and its customers have historically enjoyed the benefits of a hydroelectric-based utility. The availability of hydroelectric power depends on the amount of snow pack in the mountains upstream of Idaho Power's hydroelectric facilities, reservoir storage, springtime snow pack run-off, rainfall and other weather and stream flow management considerations. During low water years, when stream flows into Idaho Power's hydroelectric projects are reduced, Idaho Power's hydroelectric generation is reduced. Extreme temperatures increase demand for power by customers who use electricity for cooling and heating, and moderate temperatures decrease demand for power. Precipitation or the lack thereof also directly affects the Company's irrigation load. Weather and hydro-production are inextricably linked. 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.

2. Pricing Volatility and the PCA

Q. Does the Company's PCA remove this weather and water risk?

A. Not entirely. Although the Idaho Commission grants recovery for the majority of the variations in power supply expense through the Company's PCA, the recovery is less than 100 percent. Although originally viewed by the Company as an earnings stability mechanism, the PCA has provided less stability than anticipated. The risks associated with the Idaho jurisdictional 10 percent of variations in power supply expenses (the portion the

Company's shareholders are required to absorb) are having an increasingly significant adverse financial impact on the earnings capability of the Company. Actual results no longer provide the level of earnings stability originally contemplated by the Company.

Q. Why have the earnings stability benefits of the PCA to the Company declined?

A. While I do not profess to be an expert on the details of the PCA mechanism, from a financial perspective, I can identify one very significant factor affecting the PCA that has materially affected earnings stability.

Q. Please elaborate.

A. The Commission in 1993 authorized a PCA mechanism with the principal parts being fuel expenses, a deduction for surplus sales, purchased power expenses, and an adjustment to compensate for the difference between actual load and the load used to establish base rates.

At the time the PCA was established in 1993, there was a fundamental relationship between FERC jurisdictional rates for purchases and sales and Idaho Power retail rates. All of the prices or rates were cost-based.

In 1997, FERC determined that it would permit market-based rates as opposed to cost-based rates. While

Idaho retail rates remained cost based, FERC jurisdictional rates for sales and purchases became market based. The cost or price for both FERC jurisdictional power purchases and sales attributable to Idaho Power increased significantly. This created an enormous difference between the monetary amounts for purchased power and surplus sales that the parties considered in 1992 and 1993 when the PCA methodology was established and the costs and prices experienced in recent years. This volumetric change is truly monumental when you consider the financial size of Idaho Power. Company witness Said informed me that average Idaho Power purchases for the period 1993 though 1996 were at an average expense of $22,389,000 per year. For the period 1997 through 2007, the average Idaho Power purchases were at an average expense of $217,265,000. Likewise, surplus sales for the period 1993 through 1996 were at an average revenue of $42,060,000. For the period 1997 through 2007, the average sales were at an average revenue of $186,711,000.

Q. Did you ask Mr. Said to provide you with information as to the decline in PCA earnings stability benefits since the inception of the PCA due to increased prices?

A. Yes. Mr. Said has informed me that at the time of the inception of the PCA, the Company, interested parties, and the Commission envisioned power supply expenses would vary $120 million from a high-water scenario to a low-water scenario. With base rates set at the mean of the range and 90 percent sharing by customers, the Company's exposure to adverse water power supply expenses was $6 million (1/2 * $120 million * 10 percent = $6 million).

Mr. Said also informed me that the range of power supply expenses from a high-water scenario to a low-water scenario is now $290 million. Using the same computation I just presented, the Company's current exposure to adverse water is $14.5 million (1/2 * $290 million * 10 percent). That means that the risk exposure today is 2.4 times as great as it was at the time the PCA was adopted. This increased dollar amount that is at risk should be recognized in the Company's return on equity in light of FERC market-based rates and how those purchase power costs are calculated and treated in the Idaho PCA mechanism.

Q. Does your recommended 11.25 percent return on equity reflect this increased risk to the Company based upon the expanding range of power supply expense possibilities?

A. I allowed for the increased volatility in the markets, assuming the current PCA operates as ordered in the Company's most recent general rate case. In doing so, I am assuming there remains a possibility in the future for the PCA mechanism to be symmetrical and for both benefit and cost sharing to occur. However, if the PCA requires the shareowners to absorb 10 percent of the costs <u>every</u> year resulting from weather and escalating market prices, my recommended return on equity is too low.

Q. If the PCA only results in cost sharing (recovering less than 100 percent of its power supply costs) going forward, as it has for each of the last eight years, is your recommended return sufficient to attract capital at reasonable prices?

A. No.

3. LGAR Implications

Q. On January 9, 2007, the Commission issued Order No. 30215 concerning the LGAR in the PCA mechanism. Are you aware of that order?

A. Yes.

Q. How was that Order received by the financial community?

A. It heightened their concern that the Company will be unable to earn its allowed rate of return. A. G.

Edwards & Sons, Inc., issued a research report on February 16, 2007, stating: "The revised LGAR mechanism and use of the historical test years in rate cases makes it difficult for IDA to earn its allowed ROE in periods of strong customer and rate base growth." A similar report from Wachovia Capital Markets, LLC, on February 15, 2007, states:

> With the resulting regulatory lag and reduced prospects for Idaho Power to recover its authorized return on equity, in our view, the decision reduces confidence in the regulatory backdrop, especially as the Company begins to enter a new base-load build cycle. Moreover, more frequent rate case filings equate to more cost, more time, and more uncertainty.

Q. In Order No. 30215, did the Commission discuss the relationship between the load growth adjustment and the return on equity?

A. Yes. In that Order, the Commission stated: "[B]ecause this process (the adjustment of load growth recovery) puts the Company at some business and financial risk, it is awarded a commensurate equity return." (Order No. 30215 at p. 10).

Q. What does the Commission's statement mean to you?

A. It communicates to me that the additional risks borne by the Company due to the denial of load growth costs are to be offset by a commensurate equity return. As the load growth adjustment rate increases, the return on equity component must also increase.

Q. On February 28, 2008, the Commission issued Order No. 30508 ordering a change in the Company's base rates. Are you aware of that order?

A. Yes.

Q. How did that order address the LGAR in the PCA mechanism?

A. Order No. 30508 adopted the relevant portions of a settlement stipulation which essentially did two things relative to the LGAR. The parties to the stipulation agreed "to make a good-faith effort to develop a mechanism to adjust or replace the current LGAR to address the costs of serving load growth between rate cases." In addition, for the 2008 PCA, it was decided that "the LGAR will be $62.79 per MWH applied to one-half of the load growth occurring during each month within the PCA year."

Q. How was that Order received by the financial community?

A. It was viewed as somewhat positive but inadequate. It did not fully settle certain issues, such as the LGAR, in a manner that lessened the impacts on the Company. When the proposed settlement was announced, Standard and Poor's responded by lowering the corporate credit ratings for both Idaho Power and IDACORP from BBB+ to BBB. Additionally, both Fitch Ratings and Moody's Investors Service made reference to short-comings in the PCA mechanism and negative impacts from the load growth adjustment as contributing to their negative ratings outlooks later in 2008.

RBC Capital Markets also made reference to both the settlement and the load growth issues in their February 14, 2008, Equity Research Company Update. Under a column headline of "Disappointing rate case settlement leaves important questions unresolved," they stated:

> . . . changes to the LGAR mechanism and discussions about a forecasted test year were tabled pending further discussions. S&P downgraded IDA to BBB from BBB+ due to the pending rate case outcome and its impact on cash flows.

RBC Capital Markets also indicated additional concern about the load growth adjustment mechanism stating: "The current Load Growth Adjustment Mechanism (LGAR) in place essentially punishes IDA for this growth."

Q. Does your rate of return recommendation reflect the financial community's concerns regarding the load growth adjustment?

A. My rate of return is intended to reflect the Company's current level of risk. At 11.25 percent, the return is higher than the Company's prior authorized rate of return and the changes to load growth-related power costs have contributed to that increase. My recommended rate of return on common equity would need to be increased further if the upcoming load growth adjustment workshops were to result in the Company bearing any greater portion of the costs associated with serving increases in customer load. Likewise, a reduction in, or removal of, the Company's exposure to load growth related costs would allow for a reduction in my recommended return on common equity rate and would be welcomed by the financial community. I would expect a favorable change in this risk category to be noticed in future Company ratings actions and the credit rating is a key component of determining the cost of future debt issuances.

4. Water Issues

Q. Are there any other water or weather-related risks of the Company that you would like to comment on?

A. Yes. Comments from credit rating agencies and analysts have expressed concern about the potential impacts from aquifer recharge and water rights. Reliance on hydro generation in general has come under scrutiny with recent history delivering so many below-normal water years in our region. While it is difficult to quantify potential exposures, the heightened level of discussions and disagreements within the state on these issues have increased the Company's risk profile in the financial community.

Q. Has anyone in the financial community tried to quantify the risks relative to hydro exposure for the Company?

A. Yes. While all of the rating agencies and much of the equity analyst community have commented on the significant level of risk the Company faces in regard to its high reliance on hydro power, Standard & Poors actually reviewed the hydro issue specifically for Northwest utilities.

On January 28, 2008, Standard & Poors issued a report titled "Pacific Northwest Hydrology And Its Impact On Investor-Owned Utilities' Credit Quality." This report took an in-depth look at hydro implications for investor owned utilities in the Northwest. In regard to Idaho Power specifically, Standard & Poor's stated that "Idaho Power's regulatory mechanisms are strong, relative to the other companies in our survey, but not strong enough to overcome significant exposure to the variable flows of the Snake River." They went on to indicate the financial implications to the Company related to this and other factors as described below:

> Despite having both a PCA and an update process, the mechanisms have not been able to fully insulate the company from the highly variable and generally low flow conditions that have persisted on the Snake River for the greater part of the past decade. Idaho Power's financial performance has been also hampered by a load growth adjustment mechanism that has resulted in a cash loss on new customers, and regulatory lag due to the use of a historical test year for the non-fuel component of rates.

5. Relicensing the Hells Canyon Complex

Q. Please describe the risks regarding 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 result from efforts to renew the federal licenses of these facilities could have a significant financial impact on the Company and the prices its consumers pay for electricity. Because of its importance, the Company has committed to expend significant financial and human resources to obtain new licenses for its hydro generating capacity from the FERC.

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. This uncertainty combined with the potential loss of generation capability due to operational changes, and the magnitude of the financial impact of unknown Protection, Mitigation, and Enhancement ("PM&E") costs are financial risks to the Company.

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 related to these projects are also difficult to quantify. The potential financial magnitude of these PM&E and their effect on the Company's low-cost hydro generation 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; however, in all cases, they can be significant due to lost generation capacity, 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 relating to 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.

Q. Please address the risk specifically associated with the Company's relicensing effort before the FERC 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 2003 and accepted by the FERC for filing in December 2003. The FERC process moves at a slow and deliberate pace due to the large number of interested parties involved in evaluating the application, thus the timing of the issuance of a new Hells Canyon facilities license remains uncertain. Historically, FERC has given the Company an annual license renewal (under the existing old license) until the formal new license is issued. It is difficult to predict the ultimate financial impact of the relicense until the new FERC license is issued and all of the relicense conditions are known.

Q. Please comment on the relicensing efforts that the Company has already undertaken.

A. As part of the FERC relicensing regulations and pursuant to the Federal Power Act, the Company is required to conduct numerous studies and evaluations concerning botanical issues, land management issues, hydraulic issues, flow modeling issues, sedimentary issues, water quality issues, aquatic issues, recreation issues, cultural resource issues, and fish and wildlife issues.

Q. How does the Company account for the cost of these projects?

A. Although Company witness Miller describes this in greater detail in her testimony, Idaho Power books the project costs to CWIP because they are part of the relicensing process pursuant to FERC and state accounting requirements. While the costs are included in CWIP, the Company accrues a capitalization charge commonly referred to as an Allowance for Funds Used during Construction ("AFUDC"). The AFUDC is a non-cash item that represents the cost of related debt and equity financing. The component for AFUDC attributable to borrowed funds is included as a reduction to interest expense, while the equity component is included in other income. The total amount of AFUDC is charged to CWIP.

Q. What will occur when the Company receives a new license for the Hells Canyon facilities?

A. The amounts in CWIP will be transferred to plant in service and the accumulation of AFUDC will cease. The result will be a large increase in rate base with earnings of the Company declining since there will be no AFUDC. Because this is a relicense of an existing hydro facility, there will be no increase (if not a decrease due to operational changes) in the generation of power and thus no increase in sales revenues. The financial industry sees this as a risk that confronts the Company which can be summarized as follows: upon receipt of a relicense, (1) the Company's earnings will go down (no AFUDC), (2) the Company's rate base will go up (transfer from CWIP), and (3) no additional sales revenues (same plant but new license). For the period of time the new rate base is under review by the Commission, the Company will earn no return on roughly $100 million of investment. This lag combined with the potential for some disallowance is a significant risk factor.

Q. The Company is suggesting certain changes in the methodology surrounding AFUDC regarding CWIP balances for relicensing. If adopted, will this remove the risk that you refer to above?

A. No. The recommended change will keep this risk factor from continuing to grow but it does not fully remove the exposures described above. If accepted by the Commission, the recommendation by Company witness Miller will keep the CWIP balance related to relicensing from growing but it does not deal with the large accumulation of costs already in CWIP that will need to one day be transferred to rate base. As of December 31, 2007, that balance was $95.6 Million.

6. QF Concerns

Q. Does the regulatory treatment of energy purchases the Company makes from PURPA QFs increase the financial risk to Idaho Power?

A. Yes. The regulatory treatment of QF expenditures provides for a one-for-one recovery of dollars expended, but does not provide for a return to compensate the Company for this activity. The Company is, in effect, buying and selling energy pursuant to a legal mandate, without any compensation for providing this service. Simplistically, this regulatory treatment is similar to requiring a person operating a business to buy a product at the same price it must be sold. 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 energy purchase programs, but merely pointing out the cost of the financial risk(s) arising from a QF transaction, and that this risk should be reflected in a higher return on equity to credit the Company for its QF contracts.

Q. Has the Commission previously considered 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 five percent of the gross payments made to CSPP's [QFs]. 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.

According to Company witness Said, the current expected normalized cost for QF purchases is approximately $63.3 million. Utilizing a five percent management fee, as recommended above by Staff witness Drummond, on these normalized QF costs would result in a payment to the

Company of approximately $3.165 million. Mr. Said evaluated the impact of an additional $3.165 million of required revenues and approximated that the increase would correlate to an additional 20 basis points of ROE. That increase would bring my recommended ROE to 11.45 percent.

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 proportion of equity to debt 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 in May of 2003, noted that such agreements are "debt-like in nature" and that the increased financial risk must be considered in evaluating a utility's credit risks.

> Standard & Poor's Ratings Services views electric utility purchased-power agreements (PPA) as debt-like in nature, and has historically capitalized these obligations on a sliding scale known as a "risk spectrum." Standard & Poor's applies a 0% to 100% "risk factor" to the net present value (NPV) of the PPA capacity payments, and designates this amount as the debt equivalent.
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> Standard & Poor's evaluates the benefits and risks of purchased power by adjusting a purchasing utility's reported financial statements to allow for more meaningful comparisons with utilities that build generation. Utilities that build typically

finance construction with a mix of debt and equity. A utility that leases a power plant has entered into a debt transaction for that facility; a capital lease appears on the utility's balance sheet as debt. A PPA is a similar fixed commitment. When a utility enters into a long-term PPA with a fixed-cost component, it takes on financial risk. Furthermore, utilities are typically not financially compensated for the risks they assume in purchasing power, as purchased power is usually recovered dollar-for-dollar as an operating expense.

7. **Growth and Timely Cost Recovery**

Q. Please describe the risks relative to the Company's ability to recover significant capital investment required for present and growing electrical requirements.

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 projects a construction budget of between $270 to $290 million in 2008 and an approximate $900 million of new construction expenditures over the three-year period of 2008 through 2010. The $900 million estimate excludes any estimated expenditures related to certain large transmission projects or costs associated with a base load combined cycle combustion turbine that could increase construction costs during this time frame. Construction investments of this magnitude introduce two elements of risk: first, the ability of the Company to attract the required capital and, secondly, the recovery of these investments is on a deferred basis and subject to the regulatory process.

Q. Has the Company been able to earn its authorized return on equity during recent years?

A. No. In fact, the Company's actual return on equity has been less than 9 percent for the last five years.

Q. What has prevented the Company from earning its authorized or allowed return on equity?

A. I have previously addressed in my testimony several issues which I believe adversely impact the Company's ability to earn its authorized return. However, in my opinion, the reliance on historical test year information is a primary reason the Company fails to earn its authorized or allowed return on equity at this time. I believe this opinion is universally held by financial analysts that follow Idaho Power/IDACORP. Idaho Power is in a consistent position of always recovering its costs on a historical basis when its costs are constantly increasing on a prospective basis. As a result, there is a consistent recovery lag. As long as Idaho Power is building to meet future demands while collecting rates based in the past, it can never "catch-up."

Q. What effect does growth have on the use of historical data?

A. Growth inherently worsens the effects. Operation & Maintenance ("O&M") expenses typically rise faster than inflation as new facilities and personnel are added to meet growing customer demands. Yet recovery is based on lower historical costs and staffing levels from a prior period. Likewise, the allowed rate of return is applied to a rate base from a prior historical period and new plant additions suffer some period of zero percent return awaiting eventual rate base treatment.

8. Declining Credit Ratings

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

A. Idaho Power Company's credit ratings as of June 20, 2008, are as follows:

	S&P	Moody's	Fitch
Corporate Credit Rating	BBB	Baa 1	None
Senior Secured Debt	A-	A3	A-
Senior Unsecured Debt	BBB- (prelim)	Baa 1	BBB+
Short-Term Tax-Exempt Debt	BBB/A-2	Baa 1/VMIG-2	None
Commercial Paper	A-2	P-2	F-2
Credit Facility	None	Baa 1	None
Rating Outlook	Stable	Negative	Negative

Q. Standard & Poor's downgraded the Company's credit rating in January of 2008. What prompted this action?

A. Standard and Poor's lowered the corporate credit ratings for both Idaho Power and IDACORP from BBB+ to BBB, citing cash flow concerns, the proposed general rate settlement, and specifically mentioning the impacts of load growth. Their research update on January 31, 2008, stated:

> The rating action was driven by a gradual deterioration of cash flow coverage and last week's proposed general rate case settlement, which does not sufficiently address long-term ratemaking issues tied to rising costs and load growth pressures. Over time, average credit metrics have deteriorated, and the company has been unable to stabilize returns and cash flow with existing rate mechanisms. The proposed settlement

calls for an average 5.2% rate increase but does not settle some important, policy-related issues in the case, such as the use of a forecasted test year or the appropriate level of the load growth adjustment credit.

Q. Have there been other ratings actions in 2008?

A. Yes. Both Fitch Ratings and Moody's Investors Service recently changed their ratings outlooks for both Idaho Power and IDACORP to "negative" from "stable" on March 20, 2008, and June 03, 2008, respectively.

Q. Do you believe that the current credit ratings of Idaho Power Company are adequate?

A. Other utilities with the same credit ratings as Idaho Power Company are able to raise capital in today's markets. However, these new debt/bond issues are at a higher cost than if these utilities had a higher credit rating (the higher the credit rating, the lower the cost). This results in passing on higher interest costs to customers over the life of the bonds.

One large threat to Idaho Power Company's current ratings is unforeseen risk. Should an unforeseen event cause Idaho Power Company's short-term credit ratings to be lowered, Idaho Power Company would no longer be able to issue commercial paper. This would limit the options Idaho Power Company has available to meet on-going cash requirements, such as funding capital improvements and paying for deviations in power supply costs, and would likely result in higher interest costs to the customer. The unforeseen risk has a potentially greater impact when a company is closer to the bottom of what is considered "investment grade."

Q. What is the lowest rating that is considered investment grade?

A. For Standard & Poors that rating is BBB-. Idaho Power's corporate credit rating is currently one step above that bottom rating. Its senior unsecured debt rating is actually at that bottom level and its secured debt rating is currently at A-. A significant concern for me, as the officer primarily responsible for providing the Company's capital, is how close Idaho Power is to the bottom of investment grade status. The concern is only heightened by the need to raise increasing amounts of capital in the near future for some fundamental infrastructure improvements. The last time Idaho Power faced this situation we carried much better credit ratings than today.

9. Reasonable Actual Results

Q. Why do you think the rating agencies have taken their recent actions to reduce Idaho Power's credit ratings?

A. I think the single largest contributor is the fact that actual results have varied so significantly from any type of expected return. Idaho Power's last return on equity arising from the settlement of the 2005 general rate case was 10.6 percent and while several rate actions have been completed since that time, the approximate expectation for a regulated return has stayed very close to that figure. Yet in actuality, the realized returns have been far below that figure, not reaching double digits since 2002.

Q. Has the Company been able to earn its allowed return on equity in recent years?

A. No. During the years 2004 and 2005, Idaho Power's authorized return on equity was 10.25 percent. In those years the Company earned a return on equity of 7.2 percent and 7.7 percent, respectively. In 2006, Idaho Power's actual return on equity was higher but still barely over 9 percent in a year that enjoyed good hydro conditions. In 2007, Idaho Power only earned an actual return on equity of 6.9 percent. In fact, the actual return on equity for the Company has not been above 10 percent since 2002 when the Company earned 10.9 percent against an allowed return on equity of 11.5 percent.

Q. What drives this continual earnings short-fall?

A. I believe the primary contributors to be the effects of regulatory lag and a combination of negative impacts arising out of variability in hydroelectric generation. Although I have addressed several other risk factors in my testimony that also contribute to the short-fall, I would like to emphasize that the financial community and the recent ratings actions are looking very directly at the actual results of Idaho Power's regulatory efforts. They expect realized rates of return to be near allowed levels, or at least occurring at or above allowed levels as often as they fall below them. The financial community is also certainly looking for more consistency in cash flows.

CAPITAL STRUCTURE

Q. Would you please describe Exhibit No.27?

A. Exhibit No. 27 details the calculation of the Idaho Power Company capital structure for long-term debt, the common equity balance resulting from the Company's forecasted year-end 2008 capital structure as provided to me by Ms. Lori Smith, and the resulting overall rate of return that I am recommending.

Q. The capital structure presented on Exhibit No. 27 incorporates changes to the Company's 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 treated as O&M expenses. Even with these exclusions, the capital structure presented in my Exhibit No. 27 is reasonable in light of industry and rating agency criteria.

Q. Would you please comment on Exhibit No.28?

A. Exhibit No. 28 details the calculation of the cost of debt used in the estimated year-end 2008 capital structure. The cost of debt is 5.927 percent. Please note that one forecasted bond issuance of $125 million appears on line 12. The $125 million issue will be used to redeem outstanding short-term commercial paper as well as financing ongoing capital expenditures. The interest rate for this issuance was derived by averaging quotes for ten-year First Mortgage bonds from three investment banks as of April 7, 2008. In addition, the Company assumed that the Sweetwater and Humboldt County bonds would be remarketed in a fixed, ten-year mode before the end of the year. Idaho Power averaged quotes from two investment banks for similarly rated bonds. These rates were estimated at the time the overall cost of capital rates were needed to prepare a rate case filing.

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

A. Yes. The Company currently utilizes one variable rate security in its long-term capitalization. The Port of Morrow (Boardman) Pollution Control Revenue Bonds Variable Rate Series 2000 ($4.36 million) is listed on line 15 of the exhibit.

Q. Would you please describe the variable rate nature of this pollution control bond?

A. This variable rate pollution control bond, although considered a long-term security, has features that allow the Company to take advantage of rates applicable to short-term securities. The interest rate is determined the first day of a weekly period by a Remarketing Agent. 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.

Q. How did you determine what rate to use for the Boardman Variable Rate Bond?

A. I used the methodology authorized in the 2003 rate case (Order No. 29505) that utilizes the average rates observed for this specific bond over the last five years.

Q. Please comment on the structure and rates for the Humboldt and Sweetwater County bonds and how they differ from the last rate case.

A. In the last rate case, the Sweetwater and Humboldt County bonds were in an auction rate mode that reset periodically (every seven days for Sweetwater and every 35 days for Humboldt). The mode had produced short-term rates for the long-dated securities even lower than the Boardman Variable rate bonds and these benefits have been passed on to the customer through a lower overall cost of capital structure since 2003. However, in February of 2008, the entire auction rate market began to deteriorate rapidly based on overall credit worries in the market, specifically around the mono-line insurers which guarantee a large portion of the debt in this market. Both the

Sweetwater and Humboldt bonds began to experience much higher reset rates through the auction process (e.g., between seven - ten percent for Sweetwater). The Company arranged for a short-term loan and used the proceeds to purchase these bonds and hold them in Idaho Power's name. This is a temporary solution, and the Company expects to remarket these bonds in a longer term fixed mode before the short-term loan expires in March of 2009.

OVERALL COST OF CAPITAL

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

A. As shown on Exhibit No. 27, using the projected year-end 2008 capital structure provided to me by Ms. Smith, the 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 8.55 percent.

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

A. Yes, it does.